CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

2005 ENERGY REPORT COMMITTEE

WORKSHOP

RENEWABLE RESOURCE POTENTIAL IN CALIFORNIA

AND INTERSTATE RENEWABLE RESOURCES

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

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SACRAMENTO, CALIFORNIA

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Peter Petty
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COMMITTEE MEMBERS PRESENT

John L. Geesman, Commissioner and Presiding Member

James D. Boyd, Commissioner and Associate Member

Mike Smith, Advisor

Jackalyne Pfannenstiel, Commissioner

Tim Tutt, Advisor

STAFF PRESENT

George Simons

Drake Johnson

Dora Yen-Nakafuji

Elaine Sison-Lebrilla

Michael Kane

Grace Anderson

ALSO PRESENT

Bryan Jenkins
UC Davis

Ray Dracker
CRS

Ryan Wiser
LBL

Dennis Woodford
Electramix

Jon Wellinghoff, Attorney
Beckley Singleton

APPEARANCES (continued)

ALSO PRESENT (continued)

Ron Davis
DPC

Robert Anderson
San Diego Gas and Electric

Hal Laflash
Pacific Gas and Electric

Gary Allen
Southern California Edison

Scott Anders
SDREO

Nancy Rader
Cal WEA

Vince Schwent
CAL SEIA

Julee Malinowski-Ball
Public Policy Advocates

Jim Filippi
Pacific Gas and Electric

Jorge Chacon
SCE

Jeff Miller
CAISO

Dan Adler
CPUC

Steve Munson
Vulcan Power

Bob Anderson

Thomas "Tod" O'Connor, Consultant

APPEARANCES (continued)

ALSO PRESENT (continued)

Hannah Apricot Eckberg
SEIA

Jane Turnbull
CA LWV

Hal Romanowitz, President and COO
Oak Creek Energy Systems, Inc.

Sarah Myers, Attorney
CFEERT

John Galloway, Senior Energy Analyst
Union of Concerned Scientists

Carl Weinberg
SEIA

I N D E X

I N D E X (continued)

P R O C E E D I N G S

PRESIDING MEMBER GEESMAN: This is another in a continuing series of workshops of the Energy Commission's Integrated Energy Policy Report Committee. Today's topic is Renewable Resource Potential in California and Elsewhere in the West.

I am John Geesman, the Presiding Member of the Commission's Integrated Energy Policy Report Committee. Today we are actually fortunate to have Commissioner Pfannenstiel with us, which will turn it into a joint workshop between the Committee's Renewable Resources Committee and its Integrated Energy Policy Report Committee.

Commissioner Pfannenstiel is the Associate Member of the Commission's Renewable Committee. To my immediate right is Melissa Jones, my Staff Advisor, and to her right is Commissioner Jim Boyd, the Associate Member of the Commission's Integrated Energy Policy Report Committee and the Presiding Member of the Commission's 2003 Integrated Energy Policy Report Committee.

This topic is one that has played a central role in our 2003 Integrated Energy Policy

Report, was carried forward as a primary topic in the 2004 update, and it remains to be a primary topic in the 2005 report.

Commissioner Pfannenstiel, did you have anything to add?

COMMISSIONER PFANNENSTIEL: I would only like to welcome people here to the workshop and hope for active participation. I just think that the material that we are covering today and the results of today will form the basis for a lot of what not just goes into the IEPR Report, but in fact a lot of the work at the Energy Commission, so I look forward to a very effective day. Thanks, John.

PRESIDING MEMBER GEESMAN: Commissioner Boyd.

COMMISSIONER BOYD: Thank you. Just a quick comment also welcoming everybody and thanking everybody for coming. As a former immediate past member of the Renewables Committee, this subject is something that I remain keenly interested in as evidenced by what we had in the 2003 IEPR and the additional work we are going to be doing on various forms of renewable energy in the future having just created a bio-energy

working group, etc. etc. This is an issue of key importance to us, so I look forward to listening and learning today. Thank you.

PRESIDING MEMBER GEESMAN: George, why don't we turn it over to you.

MR. SIMONS: Good morning, I am George Simons with the PIER renewables area. We have a pretty full agenda in the morning as well in the afternoon. We are going to hear about a variety of different renewable resources within this state this morning.

Primarily what we call the technical potential, this will not cover the economic potential. It will not cover any of the transmission issues associated with developing renewables in California.

We will have a panel discussion at the back end of this morning's presentations. In the afternoon, we are going to shift and we will talk about renewable resources outside of California, primarily in the WECC states and some of the transmission challenges and issues that we face.

Again, we will have a panel discussions, some comments, and then a wrap up.

A little background on this proceedings.

Back in 2003, the Energy Commission did present some findings about the technical potential of renewable resources in California. That was in the Renewable Resources Development Report. That is available on line through the Energy Commission's web pages.

What we are going to, again, be covering today is the in-state renewables within California in the morning and then in the afternoon shift.

I do want to mention -- I do not want to sell tickets in advance for the upcoming June 23 workshop, but I think what is going to become very apparent this morning -- well, by the end of the day, is that there is going to be a tremendous emphasis on in-state renewables within California.

I think when we begin to look at one, there are tremendous resources, both inside California as well as in the WECC, that one of the big challenges facing California will be the transmission constraints and capacity problems in getting electricity into California.

By 2010, I think all of the sudden, the emphasis will be back on what kind of renewables can we develop economically and with transmission realistically developed in the state by 2010.

Again, we intend to have a June 23 workshop to go ahead and bring those issues up.

I am going to go ahead and shift this on over so we can get started with the first presentation, and that is going to be Drake Johnson.

MR. JOHNSON: Good morning, Commissioners, good morning colleagues. My purpose here is going to be very brief. George already stole part of my thunder, which wasn't very loud to begin with.

What I would like to do is to just sort of set the stage for this workshop in the sense that back when the renewables portfolio standard was passed with Senate Bill 1078, we here at the Commission were tasked with the assignment to try and get some kind of assessment of how much renewables would be required in terms of the energy amount for meeting that requirement and what the potential for development was.

We charged along doing that, and in doing so we developed a renewable resource development report, and we looked at a number of different estimates or studies or assessments of potential renewable, and that is shown here on

this slide by the band width of them, and we settled on for our renewable resource development report those that are in the purple dots, and that is the ones and you can look at it what we used.

We included discussions with PIER, we had public workshops to take public input. This is sort of just where we ended up, kind of picking up from where we left off in the last planning cycles back in EER 96 Bureau or so.

From there, we also took a look at outside of California, barters for the potential, we found there was an extremely untapped amount of renewables outside of California. We based that primarily on the energy atlas of the west, and ultimately developed what is called the Renewable Resource Portfolio which George mentioned to you earlier.

This report you can get those numbers either on the web or from our dockets area, and it is I think it is very well written document in the sense that it is well documented where the sources of information and stuff in it have been arrived and derived from. So, it serves as a beginning actually of what we are doing today.

This is really the spring board of

what's going on, and so without any additional discussion, the next one is Dora, we can start with the wind resources and see where we've moved from in the last couple of years in terms of our knowledge and understanding of the development of renewables in California and outside.

MS. YEN-NAKAFUJI: Hi, good morning everyone. My name is Dora Yen-Nakafuji, and I am in the technical lead for the wind renewable resources for the PIER program.

What I would like to talk about really is the technical potential within California wind resources and how we -- basically, I will quickly review the goals of the wind program within our PIER program, focusing more on the SVA approach, providing a basic overview where all of the resources will follow in the same way, a similar way of how the strategic value assessment is utilized for this study.

I will talk a little bit about our past and present wind resource assessments and how that we can leverage for this activity and go over the technical results we have thus far and conclude with a brief summary.

In terms of goals for California, our

priority really is to assess and understand and characterize the wind potential within the state and reduce our intermittency issues. In order to meet our RPS goals, we have to combine the understanding of the characteristics, the availability of the characteristics, as well as the technical operational capability of the wind resource.

As you see here, it really integrates all of the aspects of characterizing the wind, looking at its benefits, the transmission, as well as taking on tools and methodologies that we can actually model a lot of these resources to make sure that they comply with operational needs and also meet RPS goals.

This is the flow for the strategic value approach. As George mentioned, we are really only concentrate on the technical potential today with the opportunity to refine the assessment going into the economics and come up with the final integrated results.

This runs through the entire flow. We begin with the initial resource assessment by identifying the resource potential and with a series of filtering criteria, we come down to a

technical availability.

From there, we will then look at the economics by coupling it with grid transmission capacity availability, the upgrade required to actually integrate that significant amount of whatever resource, the renewable resource is, environmental impacts as well as local economies in terms of how many jobs and resources will be brought into the local area.

All of that is overlaid on a specific location to optimize a mix at a specific location, and then we will be able to graphically present a prioritized result of where to focus within a state. So, that gives you a brief summary of what's to come in June.

California has a long history of characterizing wind resources since the '80's, but technology has changed since then. As you can see, from the Altamont where we have the small 100KWh to 250 KWh machines, it has grown to our multi-mega watt machines actually over in Solano that we can find now as modern capability.

Over on the left hand side, you see our old wind resource map developed in the 80's. These were primarily more subjective contours

based on expert meteorological knowledge about a certain area, a lot of it based on meteorological (indiscernible) tower data that were measured at about 10 meters to about 30 meters.

As you can see, this is a high resolution where we have divided into two wind resource regimes, a high and a available resource site, so our main resource areas are located in these, the pink and the yellow areas.

With modern technology, we need better confidence in the data. In order to develop as much resources as we will need for the RPS, we need to have a higher level of confidence in the amount of data that we've -- the potential within this state.

In 2001, the end of 2001 we developed a high resolution physics- based model maps of California wind resources, and that provided us 200 meter by 200 meter clear resolution versus the kilometer scale resolutions in the past. It also afforded us the ability to come up with multi layer wind resource assessments that fit more modern technologies up to 100 meters.

Besides just the map, we have data behind those locations, the 200 meters by 200

meters we can actually locate or have better resolution of where the wind resources are and also the ability to look at high wind resources, high speed wind resources as well as low speed wind resources in order to characterize the different types of technologies that will be used in those regions.

We are also taking a step in looking at urban wind monitoring, bringing wind potentially DG wind resources closer to demand centers for local use applications.

This is just illustrating the data quality that we now we are afforded with these new tools. In the past, the Solano region, if you look at it, based on just meteorological expertise, we have that, the big pink glob is what I call it, but now we have been able to refine it to more of a bulls eye, and you can see the wind patterns changing, and this is a combination of meteorological expertise along with wind validation at monitoring sites and also a physics-based model to be able to generate this resolution of locating the resources.

In terms of wind potential at 70m, which is about typical height for most wind generators,

the modern turbines at this point. We have about 295,000 MW of wind, this is transferring the wind speeds that we've found on these maps to a wind power density. In terms of wind potential, it is a significant amount of wind.

Taking the next cut at that wind potential, we are looking at the technical potential which includes a series of filters, so we are looking at resources that are above 300 watts per meter squared of power density of 300 watts per meter squared looking at topography that is less than 20 meters, so we filtered out that which is greater than 20 meters. This is for ease of access to the site, so we can actually develop the land, of course bodies of water, urban areas, and other areas that cannot be developed. We have filtered those out. That reduces that gross potential to about 99,945 MW, so a significant amount of wind resources still currently installed with just a little bit under 2,000 MW. So, the opportunity is significant. This is a combination, this number is a combination of high wind speed and low wind speed.

I wanted to illustrate this particular graph. If you look at the bar chart, it

corresponds to the chart below. At 70 meters, in terms of high wind speed capability, we have about 14,000 MW potential, that is about .6 percent of land coverage area.

If we include low wind speed potential, that increases that land area by about five times that amount. There is a significant amount of resources at the low speed resource area if we can further develop those regions.

We needed to be able to prioritize our development areas and focus on within the state where we were to focus our resources initially. This graphic allowed us to look at county by county which counties should have priority in terms of development.

As you can see, Southern California has a significant amount of the darker the area the county is, the larger MW generation potential from wind. You can see areas of high potential and medium development potential. Unfortunately, many of the areas in the Central Valley are considered very low low speed wind, and it would take significantly more resources to develop those sites, but there is hope. A lot of distributed generation could potentially go into those sites

and increasing the availability of wind in those resource areas.

Looking ahead, and I am just going to show these slides as kind of teaser going into June will be overlaying the transmission what we call hot spots onto these wind resource sites and then filtering down and looking at the most benefit to the transmission impact sites.

Overlaying hot spots, selecting the wind locations where wind resources or any other renewable resource would be of benefit to the grid. That will help us focus our location where we would develop more -- concentrate the development of wind.

In this scenario, you can see where the blue dots, the concentrated dots are is where we are going to be looking at.

In summary, we do have a significant amount of wind potential in California and within the state, the opportunity to develop those sites. SVA provides us a road map, both a long term or a near term and a long term approach for adjusting those areas to meet our 2010 accelerated RPS goals.

I'm not going to go into details of each

of those, but basically, it will give us a location to focus and concentrate our efforts looking at transmission upgrades and looking at the benefits in terms of economic as well as non-energy benefits to the grid.

With that, I think Elaine Sison-Lebrilla will be talking about the geothermal resources.

MS. SISON-LEBRILLA: Good morning, my name is Elaine Sison-Lebrilla. I'm going to talk about California geothermal resources, and essentially most of what I am going to speak about today regarding the resources estimate was done and is available on the Energy Commission website and also on the GeothermEx website, it is at Geothermex.com.

I want to talk a little bit about our strategic value analysis and what we have done with geothermal plus all of the other renewable resources. We have identified and quantified and mapped electricity system needs out through 2017 looking at capacity reliability and transmission.

We have selected years in 2003, 2005, 2007, 2010, and 2017. We have identified and mapped out the geothermal resources as well as the wind, solar, biomass, and the water (hydro and

ocean).

We have projected environmental cost and generation performance of renewable technologies through 2017. These projections were developed PIER Renewable staff; corroborated by work done by EPRI, NREL and Navigant.

We have conducted combined GIS and economic analyses to obtain "best-fit, least-cost" approaches. This whole SVA project was initially done just to develop research and development targets that will help drive forward renewables capable of achieving identified benefits. This whole project really wasn't intended to be part of the RPS process, but we have found that it could help in the RPS implementation.

The SVA Geothermal Approach, what we have looked at is we have identified and quantified the geothermal resources. We have then calculated the cost of geothermal electricity generation, and then we looked at adding this new geothermal resource to the grid.

This presentation today is going to look specifically at the identification qualification of the resources. What we will go over in the June workshop will be a calculation of the cost of

geothermal electricity and the addition of geothermal resources to the grid.

The geothermal team consisted of CEC staff, GeothermEx, Inc., which essentially did most or actually all of the resource assessment. We had McNeil Technologies helping us with the cost of electricity generation models, and Davis Power Consultants, Anthony Engineering, and Power World who have modeled the California grid for us and have injected the geothermal resources and also the other renewable resources onto the model to see how that has affected good reliability. That work is going to be presented in the June time frame.

In mapping out the California geothermal resources, we've identified the types and amounts of geothermal that can help resolve hotspots. Hot spots are essentially areas in the grid that would experience difficulties when you add generation.

We thought the existing data was not readily useful for geothermal, they were not transferrable to GIS. We've had GeothermEx to a geothermal resource assessment which identifies and quantifies the resources that we have known data on.

The assessment that GeothermEx did, we've transferred that data into GIS format, but today's presentation will just look at the geothermal resource.

This is a visual of the gross resource, the map on the left is from NREL, their depiction of the geothermal resources available and the types of ownerships that the geothermal resource is on.

The map on the right is actually the known geothermal resource area and is the starting point for technical potential analysis that GeothermEx did for us. Again GeothermEx, this whole work has been completed and is available at Geothermex.com and also on the Commission website.

The scope of work for the assessment had two main components. It looked at geothermal reserves and estimates of capital costs.

The assessment had a large challenge because of the wide varying maturity of geothermal resources from geysers that are fully developed to Glass Mountain, Medicine Lake that has not been developed or has no power plants on it.

The challenge has been to objectively assess and compare resources at different stages

of development. GeothermEx came up with exploration development categories.

Category A was where existing power plants is operating. Category B where there was no operating plant, but at least one well with tested capacity of 1 MW or more. Category C was no well tested at 1 MW or more, but downhole temperatures were of at least 212 degrees F, and lastly Category D, those areas not meeting A, B, or C, but resource properties were gotten from other sources (geology, geochemistry, geophysics).

This is results from the GeothermEx assessment, and we initially had them look at both part of Nevada and the California area. These numbers were rounded up to the nearest I believe 50 MW. This map actually has the numbers from the assessment only for California, and these are the numbers for the geysers is 1468 MW, and these are the most likely capacity. Down in the Imperial Valley 2488 MW.

This is a depiction of the tool that GeothermEx used to do their resource assessment. They looked at reservoir area, reservoir thickness. They used the Monte Carlo methodology, and this is for South Brawley which ended to I

believe 62 MW -- it is hard to see. Like I said, all of this information is available via the report that is currently on the website.

This is the most likely geothermal resource for the resource areas that GeothermEx did. I think you can see Brawley South has 62 most likely, it also has the existing the gross MWs that is currently on line and what we call the technical potential which is the most likely MWs minus what is already on line is on the far right column. We have approximately nearly 3000 MW in geothermal potential in the areas that GeothermEx has looked at.

In summary, a technical reserves, estimated most likely in California is a little over 4,700 MW, the estimated incremental is almost 3,000 MW. What we need and what we have done is using filtering constraints, we've incorporated economics and transmission filters to this data to find out what is economically feasible for geothermal injection in California. That work is going to be presented in the June time frame, June 23.

Like I said, all of this work is available, published, has been for about a year,

so if anybody is interested, you can get a copy on the website or you can contact us or GeothermEX. That is it for my presentation. I wanted to next introduce I believe it is Bryan Jenkins to talk about the biomass resource assessment.

MR. JENKINS: Thanks, Elaine. Good morning, Commissioners. Good morning, it is a pleasure to be here.

This is a presentation of what we believe to be biomass resources in the State of California. What I will present today is the result of a collaborative exercise among various agencies and parties who have looked at the resource. It is a very diverse resource, and so there are a lot of assumptions in getting to the numbers that I will show you here today.

I do want to point out that the staff in the Biomass Collaborative, which is funded by the Energy Commission worked on this as well as staff from the Energy Commission and the California Department of Forestry and Fire Protection, and we have some representatives here from these agencies.

The Integrated Waste Management Board was also involved, and there are a number of other

agencies who have been involved in this effort.

There are four main categories for biomass. These are: agriculture, forestry, municipal solid waste, and other municipal waste, and then dedicated crops. Dedicated crops will appear perhaps in the future. I will not include them in today's presentation for the value's that we will see except for some projections towards 2017.

We did look at the gross resource that is available or potentially available in a state, and then from that derived a technical resource which we feel to be available for energy development based on various agronomic and ecosystem constraints and the technical constraints. This technical availability does not yet constitute an economic availability for the resource at this time.

I mentioned some of the assumptions that go into this. For agriculture, we have mainly applied yield factors for crop residues to the various crops in the state, and the state does produce something like 350 different crops, so we have a number of factors to deal with, and we do not have adequate information I would say at this

point on all of these crops, so there are some assumptions in that.

We have applied these yield factors to the acreage data based on California agriculture statistic service and national statistic service for the county data. For animal population, we have applied various standard manure estimates from animals. For food processing, we've done our own surveys of the food processing industry, as well as looked at some of the state and national data available for that in the state.

The forest estimates are coming almost entirely from the California Department of Forestry and Fire Protection.

We have for the municipal resources mostly estimates coming from the Integrated Waste Management Board and the USEPA.

If you look at the state, we have a very diverse of course land cover class and use in the state with a forest concentrated in the north and along the Sierra. As you can see with the green there, agriculture occupying the great Central Valley shrub lands in the South as well as distributed throughout the state. Then the urban areas, Los Angeles, San Diego, San Francisco Bay

Area and Sacramento Areas, being the principal areas for urban, municipal biomass.

You can see the main categories there are exclusive of the dedicated crop who don't produce much in the way of energy crops in the state currently, but we have large resources in agriculture, forestry, and the municipal area with the total tonnage of 86 millon tons per year that we believe on a gross basis can be produced in this state or is being produced in the state with a technical potential of somewhere around 33 or 34 million tons that might be available for energy utilization as well as other products.

Biomass being a very diverse resource and having a composition that makes amiable to a number of different uses, we will see competition for these resources, not just in electricity, but in fuels and chemicals from biomass and other bio-based products.

In addition to the tonnages that we've determined here, we also have coming from landfill and from municipal sewage digesters, we have bio-gas, and we estimate the total coming from those sources, most of it from landfill gas, something over 130 billion cubic feet per year of bio gas.

If we look at agriculture and break out the various categories there, you see these are in tree and vine crops with something over two million tons available each year. Field and see crops, these are things like rice straw, wheat straw, and the other crops. Corn, as we see, ethanol development in the state, we may be seeing more residue come in from corn crop for example as we use starch to produce ethanol.

Vegetables produce biomass, not much of that is likely to show up in the energy stream, most of that will be returned to the soil. The food processing sector produces some amount, much of that will be technically available and is already being used for power generation in this state.

The manure constitutes the biggest agricultural resource. We are feeding very large amounts of biomass to animals and using them to convert to other products which we consume, and as a result of that, we produce a lot of biomass out the back end of the animals, and much of that is available for energy recovery.

Agriculture as a whole produces something on the order of 20 or 22 million tons a

year of which maybe half of that would be technically available for use for energy.

On the forest biomass potential, we have again something between 25 and 30 million tons on a gross basis available, maybe 14 million tons available on a technical basis, and you can see some of the assumptions that go into the estimate of the technical availability. We are staying off the very steep slops, we stay out of stream management zones and coastal protection zones, and the coastal sage scrub and habitats and the reserves, and so the technical is reduced from the gross by that amount.

The mill residue you see there is a potential based on what we could be generating from logging. We are not producing that much mill residue at the current time, largely because we are not logging the public forest.

Thinnings would be due to stand improvement and fire management techniques, so there is a substantial amount of biomass that could be produced as a result of those forest management activities.

CDF also ran an analysis based on looking at concentrating fire management on the

wild land urban interface areas as well as some other areas. If you look at their analysis up on the right there, you can see the wildland urban interface areas where they are located. Overlaying that then are these fire threat areas that CDF has identified and in the wild land urban interface areas, we have something about two million tons a year that could produced from those areas if we concentrated on that and then about the same amount from the non-wild land urban interface areas that are at very high risk or extreme threat of fire. So, we could be generating something like four million tons a year from this fire management in the near term.

For the municipal resources, we have in this state a requirement to divert from landfill 50 percent of our waste. We are not quite there, we are currently at about 47 percent of the waste being diverted. So, we have a very large amount of material that is going into landfill, and then we have material that is being diverted. Overall, we have something close to 38 million tons of biomass that is in this waste stream. This includes things like green waste, paper, cardboard, construction wood, demolition wood, and

it does not include tires and does not include plastics, although there are small amounts of biomass in each of those. We do not consider those to be biomass resources in this assessment.

Technically what is available from a tonnage, you will notice that the 9.7 million tons per year out of the total of 38, seems to relatively low and that's because in this assessment, you will note that the landfill material we have assumed for the technical availability that we continue to landfill this resource, that we are not going to convert it to conversion technologies, although we could increase the power capacity available from municipal resources if we were to divert from landfill to other higher efficiency and higher capacity conversion technologies.

You will see the landfill gas there again constituting something like 118 billion cubic feet per feet on a gross basis, maybe two-thirds of that would be recoverable for energy use, and we have a lot of landfill gas production in the state already.

Electricity generation in this state primarily, and then the municipal digester gas as

well contributing something on the order of 16 billion cubic feet per year.

We have about billion tons of waste in place in landfill, so even if we in the near term reduce our landfilling quite a bit, we are still going to see resource extend out over the 2017 time frame, so we will continue to see landfill gas represent a substantial resource for electric power generation in this state.

If we look at the resource projections based on all of the resources, the gross resource potentially could move up to something like 100 million tons a year or about 10 percent of the current US Department of Energy estimate or plans for this gigaton biomass capacity, the billion ton per year plan that the US has.

On a technical basis, we are probably looking at about 40 percent of that resource being available for energy purposes. This will come as a result of population growth with the increasing waste, and we will see importation of materials and packaging and the like which will wind up in the waste stream, so we will be importing probably more than we export in the way of municipal biomass.

We may see dedicated crop increase in the state, possibly associated with (indiscernible) remediation with salt effected soils there.

If we look at the total electrical potential from this resource, this 86 million tons that we have available currently, we have something like 80,000 gigawatt hours or 80 TWh of electric energy potential there with a capacity something over 10,000 MW. This is reasonably high capacity factor power. These facilities could be operating at something like 85 percent, many of them already do of the ones that are operating currently.

You can see the distribution there, the three main categories, again, in agriculture, forestry, and municipal solid waste, and the gross potential again, the landfill gas, and waste water treatment plants will contribute to that as well.

The existing and planned generation in this state currently has something close to 1,000 MW, 969 MW by our current estimate producing something on the order of 7 TWh or 7,200 gigawatt hours you can see on the table up there on the left.

Of the net system power, not all of this power goes out onto the grid, so the net system power, we have about 6,000 GWh being produced currently. You can see that has remained fairly flat since the 1992 time frame. We really have not increased energy generation from biomass resources in this state since its peak in about 1990 or 1992, whereas the state of course has continued to increase in its total power consumption, something up to 180 TWh currently.

The net technical out of all of this, if we take the technical resource and subtract from it the existing and planned resource, this is what the result of that is. You can see that forestry constitutes a very large resource for us in the future as well as large amounts coming from agriculture and municipal solid waste.

Overall, we believe there to be something on the order of 25 to 30 TWh of electrical energy potential in this or something on the order of an incremental installed capacity of 3,700 MW for the state.

As we look out through the 2017 time frame, given increases in the resource as well improvements in technology, which we believe could

happen given sort of a mean efficiency conversion efficiency for biomass in the state currently of about 20 percent and by our estimate perhaps we might improve that to something on the order of 30 percent by 2017 if we are judicious and careful about the way we plan this and develop this. Then we might be looking at about adding 52, 50 to 52 TWh of net incremental capacity or generating electrical energy to this state out by 2017. To get there, of course, would constitute major increase in our current activity in biomass.

I'll stop there with that, and go on to the next resource segment.

MR. KANE: Yeah, before I get started, I would just like to apologize, I am really nervous, so I am not sure how this is going to come out. My name is Mike Kane, I am going to do a presentation on two resources, small hydro and ocean wave energy.

The California small hydro installation design is site with a developed capacity not exceeding 38 MW. California currently has a lot of hydro power, and it represents the vast majority of renewable resources on the grid at this time.

Currently the installed capacity is about 10,000 MW convention hydro power, that is dams, small dams, run of river, and the like, and about another 1,260 or 1,300 MW of storage.

Our current hydro power provides a number of very important services to the grid. It is a very important component of our support, frequency report, and it does, it has the only significant storage currently on the grid.

Of that about 12,000 MW, 11,000 or 12,000 MWs, about 10 percent or 1,260 MW represents small hydro.

The question comes. The purpose here is to find out how much more small hydro do we have. Impoundments, there are basically two types of small hydro we looked at. There are impoundments and natural water ways, and for that, we are going into a INEEL study done by the Idaho National Engineering and Environmental Laboratory.

Then we have man-made conduits which we consider the RPS eligible small hydro, and that we will review a report done by Navigant Consultants for the Commission.

The INEEL report looks at conventional generation. It looks at, again, dams, natural

water ways. In the report, they look at 763 conventional hydro powered sites and evaluate them with respect to nineteen different environmental attributes. The attributes are combined in predetermined fashion into a probability of development, and this is used as a weighting factor against what they would consider a gross potential to determine what the actual developable potential is.

Basically getting into the results, INEEL's results, you take a look at the blue, the blue represents basically the gross potential, this is how much hydro power they think there actually is. If you take a look, it is kind of broken into three types, it is basically sites currently with power, sites without power, and undeveloped.

The red is what we get -- first of all, the blue overall there is about 10,000 MWs of conventional hydro in the state. The red represents how much of it is developable given the current state of environmental policy and current thinking of just what can be done.

The problem with that of course is, that doesn't take into account that some of this is

actually large hydro. I went through the data base to determine exactly what the large hydro component is, subtract it out, and we end up with the yellow which is about -- I think it is about 1,900 MWs.

This is just simply a graph that shows you where the power is. Geographically, it is no surprise is that you tend to find hydro power where the topography and the precipitation is favorable, which in the California happens to be in the Sierra Nevada or up in the Southern Cascades.

Of course, one big short coming of the annual report is, it is a really big picture study. We can look at it and you say, okay, 1900 MW of small hydro and we get some idea of where it is, but because it is a probablistic study rather than looking at individual sites alone, it doesn't really tell us exactly where they are, and it is not really usable for purposes of transmission planning or our SVA analysis or anything like that.

The second shortcoming is that for the most part, it is not RPS eligible. By nature, the RPS law reads that to qualify as a RPS resource,

it cannot have any new diversions and no new water allotments. Pretty much all of this will require either one of the two. So, the question becomes, do we have an inventory of RPS eligible resources which is what we tried to do with our Navigant study.

What we did have Navigant do is look in pipelines, irrigation canals, anywhere that had significant water allotments and diversion. They looked at it an performed kind of a hybrid methodology. They interviewed water agencies, or they went to the water agencies themselves and kind of inspected and saw what there was, and then they kind of gathered all of the information together and did a head-flow analysis and sometimes the water agencies would tell them this is how much we think they have, and they would extrapolate this to like agencies.

What it would basically take us to is they come up with this chart that kind of looks like this, a kind of really neat chart because it tells you pretty much everything you wanted to know. We see from this chart about 231 or so coincident peak megawatts, coincident peak occurring in June, July, August, some where in

there.

We see the seasonal variation pretty much driven by the irrigation water, which is the lower portion, the purple. Above you see the municipal water which you can see it is more or less pretty much constant.

One of the littlest things you see is pretty much if you take a look at the relative peaks of the two, the municipal water and irrigation water, pretty much of the same nameplate capacity out of each of them.

This of course gives kind of geographic distribution of that. It is a little different. Actually it is significantly different from natural waterways. Here we see it tends to exist in cities where you have large municipal water districts.

In LA you see a little bit, you see a little bit right there around San Diego, and there is also some in the Bay Area. You also see some in Imperial Valley and scattered throughout the Valley, and that is kind of what you typically expect, you are going to expect to find this kind of resource where the water is used.

That is pretty much what we have on

small hydro which brings us to ocean wave. Ocean wave, it is not really new, they've been working with ocean waves well over 100 years, since the late 1890's, but the early attempts, they got as far as some demonstrations, actually full scale demonstrations of the early 20th century, but it is not really clearly why they failed. It is mostly likely that they didn't perform as advertised, and a few spectacular failures kind of indicate the designs were not really sufficiently robust to stand up to the severe ocean storms.

A third thing which almost certainly true, though I can't verify it, is they were probably uneconomic, especially compared to some of the -- especially to hydro and a few others coming on line at the time.

Interest kind of waned until the 1980s when it was kind of renewed in Europe and elsewhere. The State of California at that time didn't really get involved, hadn't become an active funder in any of this wave energy research and development. However, because some new designs are starting to come on line, we thought it prudent at least to assess the magnitude of the resource in the state.

To do this, we contracted with San Diego State University and San Diego State University, they put together a team consisting of Mirk OPrevisic, James Wilson, Chris Guay and the like, and they evaluated hydro power, the ocean wave power off the California coast and come up with basically a pretty big number, 37 GWh, but that is just the raw energy and the waves themselves.

To really convert that to at least a gross potential even, we have to take into account the water wire efficiency. You have to kind of look at the interplay between capacity and capacity factors, what is a suitable capacity factor, what would be a suitable capacity factor which would define what kind of capacity you are going to assign to a given power level.

You also have to take into account device spacing and competing uses. We obviously are not going to do the whole coast, and devices are going to interfere with each other if they are too close together, so just to account for this and so many of these factors are really not known at this point because it is all so new, they kind of used a universal factor of 20 percent. About 20 percent, that's 7.46 GWh would be the gross

capacity. Really there is no information to come up with a technical capacity at this time.

This slide basically shows where the resource is. We see two types of resource, we see green which is called a primary resource. Primary resources are high energy resources that occur in deep water near shore. Then the secondary sites which you see in the pink are lower energy, further from shore, and they really kind of anticipate them having permitting difficulties.

This is mostly because if you take a look basically from the Sonoma Coast southward down past Monterey looks to me about San Simeon or maybe as far as Ocean City, it is mostly basically one big marine sanctuary, or a series of marine sanctuary.

Even though development may not harm the sanctuaries, it is going to be a long time if ever before any of that is developed. The second site is down in Southern California which is small for two reasons. One, you do have the Channel Islands National Park there, and you also have, even though it shows it outside the Channel Islands, the resource they are referring to is actually kind of inside the Channel Islands, and the water

gets shallow. It gets much smaller waves, much lower energy levels. You can kind of see that in the chart to the right where you see basically north of Point Concepcion, you have a very high energy of 27 or more Kw per meter of coast, and whereas south, you see it really drops to a very small number of 15, 10, or less.

That is pretty much it. Thank you.

MR. SIMONS: I am going to talk a little bit about California Solar Resources. Before I do that, we are having additional copies of the presentations and white papers made. So, if you missed receiving a copy, there will be copies available later on.

I want to point out, it may not come across, but each of these technical potentials has a tremendous data base of GIS information behind it. It doesn't appear to be really important right now as you look at it, but as we begin to apply more and more filters, this information is going to be very important because it will really show us the proximity of the resources next to substations, where again you get transmission access.

Also the GIS filters really enable us to

begin looking at things. For example, when I talk about solar, you know, if we want to locate a resource on a particular geographic type, for example buildings, we have to have a data base of information there that provides us with where are those resources located, where would the buildings be.

In the case of small hydros, Mike was talking about because of some of the legislation dealing with water diversion, we may not see impoundments being developed in California. We may see irrigation canal type technologies being developed. We don't really know at this point in time, but again, that is the kind of information that is really important to have as you begin to narrow the scope down to what would be an economic potential.

One of the things that is pretty evident is that anybody who lives in California, we have tremendous solar resources. You walk in the Central Valley during the summertime, it is extremely hot. It doesn't matter if you are in the northern part of the state or the southern part of the state, we have tremendous solar resources.

The real trick on coming up with a quantitative estimate is okay, so how much of that stuff, where is it located, and what magnitude. What we really did, we wanted to estimate this more quantitatively. We wanted to come up with a gross potential as well as a technical potential, and we wanted to carve that out in two basic categories. The photovoltaic or flat panel type approach as well as the concentrating solar. Again, those are just two of the basic types of technologies you would see applied here.

What we wanted to do is we took insolation values from the National Renewable Energy Labs, climatological radiation model, and by the way, I'm not sharing blame for this, I actually want to share the credit for Joe McCabe who is in the audience, did the lion's share of this work. I don't want to pretend that I had the expertise to go through these numbers. Joe did this, and I do think he deserves a lot of credit for the information that is here.

NREL had come up with insolation values on a 10 X 10 km grid for California. We were able to take this more finely resolved information and put it into grids, which would then when we

applied it into a GIS data base gave us some way to look at the gross potential and the distribution of that gross potential down at this smaller grid level.

Then similar to what Dora talked about with the filters, we were able to go in and apply certain types of filters to then narrow the scope.

I don't know how well you can see that, probably not at all, but what you get here is these 10 X 10 Km grids with insolation values. You get the coordinates, these are average monthly insulation values by the way based on TMY, typical meteorological year data, so it is something that is based on historical insolation values. This is simply not a computer base model, but it is based on some atmospheric data that is historical.

We aggregated these over the grid areas, these 10 X 10 km grids to come up with county-wide type numbers. This gave us a cross potential, and again, you get a GIS visualization which is really nice because as you begin to go down through this data, it is really nice to know where are you at in it.

Are things making sense in terms of you would expect to see a lot of insolation down in

Southern California, so the visualization tool gives you that kind of a truthing.

Again, we applied some technical filters, and again, the visualization tool provides you that kind of feedback that, yes, things look correct.

Let's talk a little bit about the technical potential. What we did is we took that information from NREL, and we said, okay, we want to exclude lands where solar could not be practically applied, and so what we excluded were bodies of waters, forests, agricultural lands, and sensitive habitats, wildlife areas and things like that.

We excluded regions where there were northern slopes greater than five percent, and then we assumed a ten percent overall system efficiency. This is a conservative assumption, but we wanted to be conservative in this approach. Again, what you get here is a pretty standard display that makes sense, right? We know that there is a lot more sun down in Southern California, and that is exactly what the filter shows you.

I mentioned that we could aggregate

these on a county-wide basis, so what we did is we again looked at a technical potential county-wide. Now remember that this PV technical potential really canvasses any sort of application for photovoltaics, whether it is on top of a building or it is a stand alone dedicated power plant.

What you come up with is a huge state total of nearly 17 million MW. There is not enough PV manufacturing capability world wide to get us anywhere close to that. Again, that told us something that again that anybody who works in the solar arena understands that there is a huge potential here. There is solar all over the place. The real question is going to be is how much of this can we actually harness.

One of the first things we did was we said, well, let's look at what is happening in the solar arena. We don't see dedicated large scale PV plants coming on line. What we do see is a pretty rapid growth in rooftop applications. So, we said, let's jump back for a second and look at if we applied photovoltaics to the residential sector. Well, you know, we have 15 million homes in California, so what we said is, and again, one of the things I want to do before I go on here is

acknowledge the work that the Department of Forestry did for us across the board here, not just in solar, but in every single one of these resource areas, the Department of Forestry worked with us on the GIS mapping and analysis. It is not just simply pretty maps, but there is a significant amount of analysis there that allows us to really do these filters, to come up with good filters.

We worked with CDF on taking the housing developments in California through a zip code base basis, base systems to really locate where are the high population densities in California and then located photovoltaics on those residential applications. Because, again, this is just looking at the 15 million homes. The map is really easy. If you put 2 1/2 KW system on every house, you come up with about 38,000 MW of potential, that is capacity, not energy. I'll talk about that a little bit later on.

What you get here is a very interesting visual display that shows that most of these if you were to locate PV across the board in California, what you see is a higher concentration in the Bay Area and Southern California. Again, a

gut feeling makes a lot of sense. That is where most of the houses are.

Again, if you then look at let's say commiserate with the SB 1 and some of the direction that the administration about locating photovoltaics on new residential, if we just located them on new homes, what would be the potential. Well, it is about 400 MW per year. This is just 2005 housing stock.

California is growing at about a rate of 200,000 homes per year. It has fluctuated between 170,000 up to 200,000, so this number will vary depending on how much new home growth we see in California. Again, if you begin to plot that in terms of where it is, then what you would see, again, a distribution of a lot of it in the Bay Area and Southern California.

As we see movement of new home development into the Central Valley, we would see those curves change and go out in the Central Valley. We looked at the residential sector. We also wanted to look at the commercial sector because that is one of the fastest growing PV applications in this state, and we wanted to look at new and retrofit potential.

What we did is we took the building square footage from the Efficiency Group here at the Energy Commission. We had to make some assumptions about how much of that square footage was actually available as rooftop area. So, we made some fundamental assumptions. By the way, all of these presentations today, one of the things that we want is to get feedback from folks about are these assumptions, are we on, are we off about these assumptions. The white papers all contain fairly explicit explanations of the assumptions. We wanted to have a lot of clarity and transparency there.

If you see things that just don't sound right or you have additional information to correct some of these assumptions, we would love to have it.

We assume three floors per building, we assumed that we could only get up to 50 percent of the roof area available for the PV application due to shading. Similar to what we did before, we excluded areas that it would be impractical to locate photovoltaics.

The total potential there is again similar to the housing market about 38,000 MWs, so

very large potential for photovoltaics on both commercial and residential. Again, we provided a breakdown by county, so we aggregated these potentials at the county-wide basis, and again, this is where you can see the close to 38,000 MWs and again broken out by county.

I'm going to shift gears and talk a little bit about concentrating solar. With photovoltaics you can use all of the radiation coming down through sky and scattered and reflected back off the ground.

With concentrating solar, you have to use what is called direct beam solar. You can't take advantage any reflected radiation or any scattered radiation. Concentrating solar attracts the sun because if it doesn't attract the sun, it is not able to harness the solar energy.

Again, if any of you have seen the types of normal beam insolation maps that NREL has put out, this makes a lot of sense. Again, it shows a heavy concentration of solar down in the southeast portion of the state. However, now when you begin to filter out solar and you say, okay, well let's go ahead and exclude these typical areas, let's assume a system efficiency of 15 percent, a

packing factor of two, which means you can really only get half the space available for concentrating solar. No greater than one percent slope, and then the real kicker is we are only going to look at locations where the average annual direct beam radiation is greater than 6 KWh per day per square meter.

What happens is all of the sudden that huge gross potential really shrinks down, so again, a visual display shows you that, yeah, we have excluded a large amount of this state.

Nonetheless, even with that technical potential, with filtering out those things, we come up with a huge potential of over a million MWs. By the way, the white paper has a mistake in it. I refer to a 1,000 MWs, just missed by a factor of 1,000. It is an easy math error, anyway, that will be corrected on the new version that is put on the web. For anybody who downloaded the white paper on solar, there is a mistake there. There is a million MWs of technical potential.

Again, the conclusion here is that we have a huge solar resource in this state, largely untapped. There is a huge potential for

photovoltaics which is about 75,000 MWs between commercial and residential. If we were just applying PV to new homes, it would be over 400 MWs annually, and the potential for concentrating solar is in excess of a million MWs.

We are going to have a panel, but I want to go ahead and do a comparison with what Drake Johnson talked a little bit about earlier today. Because you have now heard presentations on all of the renewable resources, the technical potential within the state, and I wanted to just adjust to what we saw coming out in the 2003 in the Renewable Resources Development Report.

If you look at that -- again, I didn't do this on an energy basis, I did this on a capacity basis. The reason for that is that the numbers are so huge, I mean, the energy numbers are going to be extremely important later on when we start talking about what is economically available, how does the profile fit, but the numbers are so huge that we just kept them on a capacity basis.

What you see is that in 2003 for wind, we really only looked at the high wind resources. In this go around, we have added the low wind and

moderate speed wind resources. Geothermal, the numbers ratcheted down because of the probability distribution that we did where we subtracted off the existing geothermal.

Biomass, the numbers are somewhat larger, again, because we just went through by a process of updating the biomass resources in the state.

Water, we only really had small hydro numbers before. We have some very rough numbers on small hydro and ocean wave, but we felt it was important to bring those forward. Again, as you see in the white paper on this, we do give some geographical specificity, not only, but more certainly than we have in the past. That will come into play.

Again, the solar numbers are just huge, and I think that is kind of reflective of the fact that we are talking about a technical capacity. Again, I don't want to sell tickets to the June 23 workshop, but we have already done a fair amount of analysis on looking at what is the economic potential and what is the capability to hook the economic potential up to the transmission system in California. We feel pretty comfortable that

these numbers do shrink down, but nonetheless, there is a significant amount of renewable resources in California that can be picked up by 2010.

Elaine was just telling me that we do have more handouts available. As we break later on for the afternoon because we are way ahead of scheduled which is good, you can pick those up.

I do want to go ahead. We did create a panel because if you saw the agenda, there were a certain number of questions that we wanted the two panels to address.

The questions are not broken out by panel, but I want to go ahead -- I am not quite sure how we are going to do this. I am going to suggest that we take maybe a five or ten minute break while we set up a table for the panelists.

PRESIDING MEMBER GEESMAN: That would be fine, George. I did have one question on your CSP map and try to better understand how you came up with the million MW, did you only include the red areas, or did you also pick up the yellow areas as well?

MR. SIMONS: I believe those were just the red areas. It is still a huge number. When

you see an entire map of this state, those red dots don't look very large, but when you are getting over 6 KWh per day per square meter, the numbers add up very quickly.

PRESIDING MEMBER GEESMAN: Why don't we take a five minute break then.

(Off the record.)

MR. SIMONS: Again, this is who is on the panel. I am can mention that SEE is being represented by Gary Allen and not Jorge Chacone. We created a panel because, again, we would love and we need feedback on the approaches that we've taken, on the types of numbers that we are presenting.

I talked a little bit earlier about the June 23 workshop that is coming up. We very deliberately propped this workshop up to make certain that before we come in with numbers talking about economic potential and access to transmission, the impact on the transmission and benefits, that we are on the right path.

One of the things that we are asking the panel members to do today is give us a real good sense of are we on track, are we off track, are we missing resources that we should be looking at,

are we considering things that we really shouldn't be looking at, is the precision on the numbers so low that in fact we really need to look at how better to address these things, what kind of advice and suggestion would the panel members provide us on looking at again beginning to look at refining these numbers, and what kind of approaches would they suggest to us in terms of for the next step.

We would like to prop this stuff up, get feedback on it now, so that we in fact know that we are on the right track. We did have a number of questions posted with the agenda. I am going to go through some of these that I think is relevant for the panel. I'm not quite certain how to do this other than as we go through the panel, I would like to have any of the panel members who feel that they have an appropriate role or some feedback for us. Maybe we can just go right down through the list of the panelists and ask them for feedback.

I'll go through some of these questions. Again, these are a complete set of questions for both panels. I don't anticipate that we would ask the morning panelists to really touch on

transmission issues since we didn't do that yet. We will do that in the afternoon.

Again, one of the things that we really have to address is do we have sufficient resources for California to meet the renewable portfolio standard goals. Remember that the original RPS goal was 20 percent by 2017. The Energy Action Plan accelerated that to 2010. You've seen some of the technical potential numbers presented today. That certainly seems to indicate that there is lots of resources, but we would like to open that question to the panel.

Again, we can go right down through the line and ask people for responses. By the way, I don't want this to be something that is we are only asking these questions. If there are other things that we should be addressing, we would like to hear that from the panelists. I guess we can go ahead and start with San Diego Gas and Electric.

MR. ANDERSON: Good morning, I am Rob Anderson, I am the Director of Resource Planning for SDG & E.

In somewhat in addressing this first question, actually for San Diego we think the

question maybe should be reworded a little bit differently. To us, the right question is does California have sufficient renewable resources in the right locations so that they can be reliably delivered to customers at an acceptable cost in these time periods.

That to me is a little bit different question than this other one. I think we will all agree that the technical potential is there for all these renewable resources, but can we get them built and can we get them delivered to customers is where the real bottlenecks are going to be in this process.

From San Diego's standpoint, we feel very comfortable by 2017, yes, we would have lots of time to work through all those problems, and we could easily hit these targets. 2010 is going to be a real stretch for us. We pledge to do everything we can to achieve it by 2010, but we are running into issues and it is going to be a real stretch, but we will still look to pursue that.

We are also a bit concerned about mandated targets. We see things with mandated targets basically creating seller's markets.

Market price references tend to set floors rather than caps as what we begin to see in bits. What we would like to see is maybe a little more flexibility in how we achieve these targets, so more incentive based measures. There are other ways we can all work together, yes, to bring on as much as we possibly can that fully integrates within all of our operating needs, but without having hard set mandated targets.

PRESIDING MEMBER GEESMAN: How would you characterize it as an incentive-based target?

MR. ANDERSON: I am not sure we have all of the answers to that yet, and I am sure there is a lot of parties here that would end up saying being really skeptical for us, but we think that sitting down with various groups as we evaluate each of these technologies and what all do they bring to the table that we could find a way to work ourself up rather than setting these hard percent numbers.

PRESIDING MEMBER GEESMAN: The concern that I have is that left to our own devices, our regulatory system and your accounting system ends up backing into an increasing amount of fuel dependence. The path of least resistance is to

simply expense fuel costs through to your customers. You don't get penalized for it, your income statement, your balance sheet doesn't get penalized for it. From the regulator's standpoint, we don't really have to make any hard decisions, we just look the other way and say, wow, look at that natural gas price.

The last time we tried to forecast natural gas prices in our 2003 IEPR cycle, we developed effectively a consensus forecast, not simply our staff's projections, but projections that were pretty well reflected by all of the other stakeholders making natural gas forecasts at the time, and we got the price off by more than 100 percent in terms of today's price and natural gas.

I acknowledge it is a very rough instrument, but mandates seem to be the tool that state regulators have to back away from that path of least resistance which is increasing our fuel dependence. Somebody comes up with a better way to do it, I think we are all quite open to hearing that, but in the absence of a better way to do it, I think you need to learn to live with the mandate.

COMMISSIONER PFANNENSTIEL: May I ask a question. You said that 2010 looks like a real stretch where 2017 looks doable. What is the difference in those seven years?

MR. ANDERSON: What I can really go off of is just when we go out for an RFP, what do we really get, what gets put in front of us. That seems to be what do people think they can potential by then. What we are really seeing is what projects, where are they located, do we currently have the transmission necessary to get them delivered or not, and so it is kind of a combination of can the projects get built, and can we get the transmission done in time. So, it is really a little bit of each of those. It isn't any one of those that is the issue right now.

MR. SIMONS: Hal?

MR. LAFLASH: Hal Laflash at PG & E, I am also Director of Resource Planning. I agree with most of San Diego's comments. I don't think that we are looking for incentives. I don't think incentives are going to cause us to get it done any earlier.

What we are concerned with basically is just how much time do we have to get it done.

When we say 2010, does that mean we have the next five to six years, or does that mean we have two years to contract and three years to watch the plans get built. That is one of our concerns, that there is some lack of clarity there. 2010 is deliverables, most of these plants take at least three years to get built. Some like Geothermal even longer. We have some concerns around that. We think there is enough resource out there given the time to develop it.

It is market responsive, it is not something we are going out and doing directly, although both ourselves and San Diego have proposed at this year's solicitations include an (indiscernible) utility ownership. We are not looking to go out and develop it actually, but to do it turnkey.

We are concerned with the ability to get least cost/best fit resources over a reasonable time frame, not just what we can get in the next couple of years.

I think otherwise, other than the incentive issue, I think I agree with San Diego.

PRESIDING MEMBER GEESMAN: Let me ask you what you meant by the ability to get least

cost/best fit resources over a reasonable time period.

MR. LAFLASH: We saw a lot of good work shown today, and some of those resources are going to take more than a couple of years to get developed, and we would like to see for example, the solar, the geothermal, and some of those that take a little bit of time, we would like to see the time be given to them to get these on line in time.

PRESIDING MEMBER GEESMAN: That is what you see as better meeting those least cost/best fit criteria for your system?

MR. LAFLASH: Yes.

PRESIDING MEMBER GEESMAN: Okay. With respect to utility ownership options in your solicitation, what would that look like?

MR. LAFLASH: Right now we are proposing and San Diego I think already proposed last year, we are proposing a turnkey option where it be developed and built and sold to us upon operation. We are also proposing two types of options after they are up and running at a five year or ten year interval.

PRESIDING MEMBER GEESMAN: That will be

a feature in your next solicitation, or was it a feature in your last solicitation?

MR. LAFLASH: It will be a feature in our next solicitation.

PRESIDING MEMBER GEESMAN: I should say one of the things that I have a concern with in terms of our ability to meet the 2010 goal is what seems to be the open ended nature of the procurement cycle. I don't think either our staff or the CPUC staff have quite worked out the bugs yet in making that a workable and sufficiently timely procurement cycle for either my Commission or the CPUC to take a great deal of comfort in. I would certainly encourage PG & E and the other companies as well if there are ways in which you think that procurement cycle could be better accelerated and enforced, I think we would like to hear your suggestions. I caution you.

In an earlier meeting with Southern California Edision, I raised the same cautionary note to them. If these procurement cycles are allowed to go on and on and on and on and on without yielding desirable results, I think what the danger that you incur is that the regulators are going prescribe more standardized terms and

conditions in the contracts, and I doubt that either the utility or the renewable industry particularly want to see that, but I think a rough tool as it is, we have targets, we intend to meet those targets. Those targets have interim milestones, if we start to slip behind the interim milestones, there will be greater pressure on us to change the procurement cycle.

MR. LAFLASH: I agree with you comments and your thoughts on that. The problem is the more mandates that you put on top of mandates, the more concerning it gets for both parties. We've seen -- the IOU's aren't the only ones out there buying renewables. We have seen the muni's out there buying renewables, and we have lost proposals that would have gone to us that have gone to muni's because they have much simpler processes to go through.

The other concern with the mandate is if you get -- the closer you get to when you have to have this done, the more it becomes a seller's market. The harder it gets to negotiate these things in a shorter time frame because it changes the leverage of the two parties.

PRESIDING MEMBER GEESMAN: I understand.

MR. SIMONS: Gary Allen, do you have any comments?

MR. ALLEN: Good morning, Commissioners. I am Gary Allen from Southern California Edison. I guess I'm responding to the first question which is does California have sufficient renewable resources to meet the 20 percent target.

With relationship to the presentations that we saw this morning, what you would take away from that is that we have vast amounts of renewable resources that amply meet our needs to meet our 20 percent renewable targets, but it doesn't seem to comport with reality.

As Commissioner Geesman appropriately mentioned, we spent a year and a half working on a very few contracts that we came up with. We initially had more than 5,000 MW of bids in our 2003 solicitation.

Going through a number of what we felt were appropriate and described or regulated hoops or hurdles to get through in our least cost/best fit, we whittled that down to a short list of 1,200 MW and ultimately came up with a minimum of 150 and a maximum of like 450 MW of resources.

We weren't idle during that time frame.

We spent a great deal of time trying to get the appropriate resources, get the economically right resources. In addition, we spent a great deal of time trying to appreciate the risks that we were asking the rate payers to take in terms of the current market design and the future market design.

There are many things that are changing at the exact time that we are trying to contract for must take or very nearly must take energy. All of those things apply risks to the ratepayers that we are trying to minimize.

PRESIDING MEMBER GEESMAN: What do you think we are doing wrong?

MR. ALLEN: I guess my first response to that, and I almost parrot the PG & E representative is there are a lot of requirements on requirements, and either we are going to be in a market-driven environment or we are going to be in a regulated driven environment, but you can't be both. I see us as trying to be both.

PRESIDING MEMBER GEESMAN: I look at the gross system power report that our staff under statute publishes every year, and in 2002, the year that the RPS statute was enacted, it was

enacted on a statewide basis. We gained about 11 percent of our GWh sales from RPS qualified resources.

In 2003, that was down to 10.4 percent. In 2004, that came up to 10.6 percent. After three years of effort, I am not certain that we have as much to show for our efforts as any of us had originally hoped, and I think now is probably a pretty good time to ask how best to get back on track.

George's staff has presented information that each of your three companies have acknowledged shows a fairly substantial amount of technical potential, but from an institutional standpoint, we seem to lack the insight or appropriate tools to achieve a very simple and straightforward and statutory goal of 20 percent. So, I don't feel that we have the answers right now, but I certainly invite your company and the other two IOU's and the Muni's as well to offer us your constructive directions as to how to achieve those targets.

I think it is pretty clear that there is a very strong and policy maker will behind those targets, so I would ask your help and constructive

suggestions if there are better ways to do this.

MR. ALLEN: I will respond with just one further comment. A large part of the difficulty in contracting with resources is the availability or lack of availability of transmission resources.

There is an incongruity between the State of California desires and goals and the FERC's policies. We, SCE, has filed a petition before FERC to try to make a bridge around or through those incongruities. Until those things are resolved, there will still be a lack of incentive or motivation for transmission owners to invest in transmission that they don't know that they are going to get recovery for.

PRESIDING MEMBER GEESMAN: This Commission has been fully supportive of your filing.

MR. SIMONS: Thank you. Before we go into Scott Anders -- just cut them off.

COMMISSIONER BOYD: Hello out there. George, you didn't make the introductory comment that you should have made at the beginning of this meeting which is we have a large audience listening to this broadcast. If you are listening on your phone and you haven't muted the phone or

you can't mute the phone, all the noise that you make, all the talking, all the paper shuffling, all the coffee cups, etc. etc. comes bouncing back into this hearing room, and it is totally interrupting our process here. The other alternative will be to shut off the phone system completely because we have no ability to mute you. So, would people out there please be courteous with regard to the noise that you are making, even shuffling paper or turning pages comes bouncing back in this room. I've been through too many of these and heard too much of this.

MR. SIMONS: Thank you. Again, I want to thank all the panelists for coming here today, taking the time to come and provide us feedback. It is very important. I also want to mention with respect to the San Diego Regional Energy Office, San Diego SDREO did something very analogous to what we are doing with what we call the Strategic Value Analysis, but they've done it on a very geographically specific area, San Diego.

So, we thought it was extremely important to also get their feedback about how their approach is worked out in terms of are they getting -- are they running into the same kind of

issues that we are running into doing the same kind of approaches, so I would like to have Scott Anders go ahead and not only address the question that is on the table, but to expand a tiny bit about the general approach.

MR. ANDERS: Thanks, George. Thank you, Commissioners for letting us present here today. In response to the general question, I think the answer is, yes, from a technical perspective there are sufficient renewables. If you look at the study for San Diego County, there is 7,000 MW of concentrating solar power, a little over 1,000 MW of commercial PV, 3,000 MW of wind. SDG & E has a peak demand of about 4,000 MW.

I think technically speaking the resources are there. I think that there are a lot of other questions that we need to ask to get us to the point of actually getting those resources, but let me address George's brief intro.

It is not our study, let me clarify that we are a partner in the study with SDG & E and San Diego State University and a couple of consultants in the region. We have endeavored to do something very similar to what has been presented here today. I think we have probably drilled down to a

little bit more detailed level since we are dealing only with one area.

I like to say that San Diego Gas and Electric's territory is kind of interesting because it generally overlaps with the political boundaries, basically San Diego County. There is a small part of Orange County in there, but it provides and interesting laboratory if you will to dig in, and it is small enough to be able to do that.

For the last about eighteen months, we have been conducting some analysis, and we have really focused on wind, solar, and those are kind of the two areas that we've done some what we think is some novel work or some innovative work, particularly in wind, where we've used the data that I think everybody else is using, but we've run them through an analysis that is a little bit different.

In terms of the photovoltaics, we did something similar to what Marin County has done, and we digitized 15,000 rooftops in the City of San Diego, commercial rooftops, so we wanted to know what is the potential for rooftop photovoltaics in the commercial sector, so we have

15,000 rooftops and we have classified them in terms of roof availability and have come up with an estimate of what we think is out there commercially.

On the residential side, there are many more than 15,000 rooftops out there in our region, so we decided to take a similar approach, but again using kind of more detailed statistics, and we've been telling the Commission and the Commissioners that it is going to be ready any day now. In fact, we are a couple of months out of publication we think. We have an initial draft.

The data is pretty much there. We will be presenting some preliminary data at the May 18 workshop, the Border Energy Workshop down in San Diego, so that is where we will start to give some data.

Just a couple of follow up comments on what perhaps on what we are kind of interested, I think what we've figured out as a region is probably very similar to what the Commission has figured out during this analysis is that this leads to all kinds of questions.

What we've done is it has been very difficult to cut off the policy issues, the

economic issues, and just look at the technical, but it seems that there is a natural overflow into some of these other areas, and I think a couple of interesting questions that the Commission might consider look into is, you know, and perhaps you are doing this for that June workshop that George is selling tickets for is looking at the relative costs of this resources and even doing it on a time-of-use or a hourly basis to kind of see how they match up. How they match up with a particular utility's demands.

Also something that we are interested in is kind of looking at what is an optimal portfolio of resources including as much renewables as possible. How do they all interact, what are the synergies, what are the mutual exclusions of those resources.

These are some of the questions I think we are going to be looking at in the future, but I think these are some of the questions that have come to mind is 33 percent, 40 percent by a certain date, is it possible, well, I think we need to do some modeling along those lines to help answer that question.

PRESIDING MEMBER GEESMAN: I think San

Diego County is going to be the epi-center of the state's development of the photovoltaic market. In fact, it already has been, and I was particularly impressed by the comments that your office filed and Sempra filed in response to Commissioner Peevey's solar ACR last November, in particular the advice that both you and Sempra provided about trying to intelligently segment market sectors that offered the best opportunities.

One of the things that interested me about Sempra's filing was the suggestion of a utility equity role in some of those investments, and I think if in fact the state sets out on an approach that attempts to maximize federal tax benefits to photovoltaic installations, we would certainly want to give pretty careful consideration to leasing structures or potentially ownership structures that could involve an equity contribution by the utility.

Do you have a sense as to how the various constituencies represented in the Regional Energy Office's task force would respond to that?

MR. ANDERS: I don't want to conjecture how SDG & E would respond to that, so I will let

Rob respond to that. You know, SDSU and our office, and this isn't kind of a regional planning effort that is done by the San Diego Association of Government Energy Working Group. It might be an interesting question to pose to them as well.

Just so I am clear on your question, you are asking if there was an ownership arrangement in which the utilities had an equity stake in the ownership of the photovoltaics, do the folks have a problem with that. I don't think our office would have a problem with that. You know, the current -- I think one of the things that SDG & E or Sempra is arguing is that they should be eligible for the incentives. Again, I don't want to put words into their mouths, but they have filed comments along those lines.

Currently under the self-generation incentive program they are excluded. So, could there be an arrangement where the utilities can be an equity owner and not got rebates, I think there is a way to do it. In fact, we are seeing an explosion through the self-gen program on these kind of third-party ownership or leasing arrangements, and they raise some very interesting questions, and I think we have to be careful to

make sure that they are structured in a way that is clear and transparent.

I guess from our office's perspective and my personal opinion, you know, I think the utilities have a great role to play, and in particular, they have capital, and I think that could be used to great benefit.

PRESIDING MEMBER GEESMAN: Thank you.

MR. ANDERS: I don't know if Rob wants to respond on his part.

MR. ANDERSON: The only issue we run into is we will look at it from the customer's cost perspective, it is the incentive money that makes it low cost per customer the minute the utility steps in, it is now a much higher cost for the customer. So, yeah, we would like to find a way to bridge that gap.

COMMISSIONER PFANNENSTIEL: John, I have a more general question for Mr. Anders. Since you are doing a similar technical potential review down there, do you have any comments on the methodologies used and perhaps the results that we are looking at today in the technical potential? Does this look reasonable, do these various categories -- we have concluded that there are

some very big numbers out there, and part of the reason that we are subjecting this to public scrutiny is to get some input about whether these are reasonable numbers based on the methodologies used?

MR. ANDERS: Right, and I think a general response to that is I think that the methodology used for a statewide research effort of this magnitude is going to be very different than what we can do on a local basis.

Just looking at the numbers presented in the white papers, I think they are pretty close. You know, there are some variations, some of our numbers are slightly higher, some of your numbers are slightly higher, but I think in general they are pretty close. They are in the right ballpark.

You know, I don't exactly know what the methodologies were, but what I would suggest is I would be happy to talk to with Joe McCabe about the solar side of it, and the person in our task force that did the wind, I would be happy to put in touch with the folks that have been doing your wind analysis, and they can dig in I think into the details a little bit more.

Generally speaking, I think, you know, I

think we are both in the same ballpark roughly, at least for wind and solar.

MR. SIMONS: Great. Nancy Rader is here representing Cal WEA.

MS. RADER: I am Nancy Rader with the California Wind Energy Association. Thanks for having me here today. To answer your question, George, I think the report clearly is on the right track in terms of reasonably assessing the technical wind potential in this state. I think you might want to make it a little more clear that by technical potential, you don't mean near term development potential, but still as an indicator of that, we think it is reasonable.

For example, in Tehachapi, we see the near term plausible development number as between 5,000 and 6,000 MW where as the report shows it at 9,000 MW, and that is probably because we have assessed better. The realistic screens that will in fact come into play, like the military issue there, the over fly issue, so perhaps if we make that a little bit more clear. Still, I think it is still a ballpark good numbers and clearly demonstrate that we do have the in-state resource potential to meet our RPS goals. I hope we keep

that in mind before we start focusing our attention on out of state resources.

I have a number of relatively minor comments that I will provide to the report author, only a few of them merit mentioning here. I think first of all, the report should better convey, the wind report should better convey more prominently that much of the wind resource potential is located in just a few areas.

In 50 percent of the high wind speed potential is concentrated in just four counties and much of that is concentrated in two wind resource areas, Tehachapi and San Gorgonio.

To pull that fact from the resource report, you have to go back into the appendix and look through the tables, and it is obviously important for decision makers to know that 50 percent of the least cost renewable resource is concentrated in two areas. You know, because all of the rest is sort of -- I can't even think that far out, I am focused on those two areas, and people need to know that is the gold mine. That is the near term gold mine for this state, and we've got to get access to that.

Secondly, the report lists the

repowering potential at 900 MW in the 2003 to 2006 time frame. I think a more realistic number for that time frame would be 200 to 300 MW. The utilities have signed repower agreements for between 80 and 100 MW within this time frame to date, and I think we will be lucky if we double that. For the 900 MW number, I think the better time frame would be 2005 to 2010.

Thirdly, the abstract of the report says that the potential exists to double our current wind capacity of 2000 MW in the next five years. I hope that is an understatement because the Renewable Resources Development Report says it is significantly more than that. In fact, we need to develop more than that to meet our goals, so I think it should read at least triple.

That's it. I have to agree to some degree with what the utilities have said about the transmission barrier. It is a major obstacle in terms of meeting our goals by 2010.

I disagree with Gary Allen, however, that our goals cannot be meshed with a FERC's criteria. I think that the proposal that Edison made to FERC for (indiscernible) of the cost of the Tehachapi upgrade could have easily made to be

consistent with FERC's traditional approach by showing that configuration has network benefits.

We believe it could easily be configured to have network benefits by connecting it into the local system which clearly gives it network benefits. Unfortunately it was not presented that way at FERC, and we are very worried that the result of that is going to be either that the FERC rejects the proposal or the proposal that FERC approves goes to court and does not survive there.

In terms of a near term, what can the state do to promote transmission? I think the state needs to focus on Section 39925 of the Public Utilities Code that focuses on network benefits, it directs the Commission, the PUC to find network benefits of the proposed upgrades and to present those at FERC. That was not done in the Tehachapi upgrade case, and we are quite concerned about it.

That is all I have to say today. Thank you.

MR. SIMONS: Thanks, Nancy. I don't believe Ted Clutter is here, so we will move on to Vince who is representing CAL SEIA.

MR. SCHWENT: Thank you, George. I

guess I am probably the only person sitting here at this table who has actually built a renewable energy facility. Besides doing two stints at the Energy Commission, I also run an wind energy companies and built wind farms, I am currently in the solar business, we do large commercial solar projects. I am representing CAL SEIA which I am a board member today.

I am coming into this sort of blind, but as an ex-research scientist, I have to ask you all that unless today's reports on the technical potential for renewables was mandated by some piece of legislation, I am not sure why you did it. I mean there is virtually no useable information.

We knew all of this 25 years ago. Sure you've got a lot of solar, sure you've got a lot of wind. What we are learning is that if we meet RPS, we probably can't do it with biomass, hydro, and geothermal alone. We will have to have some wind. We will have to have some solar.

Having said that, where does that leave you? The guts of this has got to be in looking at the economics of all these resources, looking t the transmission constraints has been stated over

and over again. Until we overlay those two things, you don't have any useful information here that I can see.

What that is going to tell you is you've got 6,000 MW of wind potential in Tehachapi which for fifteen years they have been trying to get a transmission line built out of that. If it doesn't happen in the next few years, you are not going to meet your RPS goals based on in-state wind I would likely say.

We are totally dependent on incentives. We are not going to be able to play a huge role toward meeting the RPS even though our potential is enormous, thousands and millions of megawatts. You know, what difference does it make. We know there is enough sun in one little piece of Death Valley to power the United States theoretically, it just doesn't happen.

What do we need to talk about? We need to talk about economics. It will be very interesting to see what comes out in June because I am very fearful that the Energy Commission and the consultants will do a study of the economic potential of these different renewable resources and they won't talk to the industries that

actually do this for a living.

I know as a mathematician, it is real easy to make one little different assumption on the economics and, you know, you can have a number that is twice as large or half as big in terms of whatever the economic potential is.

I hope they talk and get some feedback from the people who actually do this for a living when it comes to economics.

Utility ownership, Carl Weinberg who is sitting in the audience made a wonderful suggestion in the break. If we really want to see a RPS happen, the one success this state had was back in the early 1980's when we had SO contracts. We had "Standard Offer" contracts.

To build a renewable energy project, you need five things. You need a customer, you need somebody to own it, and that probably means some incentives to induce them to own it, you need a resource, you need transmission to get it out of there, and you need permission. You need to be able to site the darn thing where you need to site it.

We don't need to study resources, but the state certainly could help with transmission

capacity. It is obviously critical. They could help with permissions. I mean how many years have we been talking about geothermal up at Medicine Lake and there is still nothing up there.

Customers and incentives, SO contracts. Utilities say they want to own these power plants, yeah, they want a private company to take all the technology risk, come up with all the initial capital, build the thing, and then they get to own it.

Wonderful. I wouldn't even bother replying a RFP like that. If utilities want to own renewables, they could have done it. Florida and Power Light owns a lot of wind. How much wind does any California utility develop and own?

Set up SO 4 contracts or some sort of standard offer contracts, give the industry a price that utilities are willing to pay, and then get out of the industry's way and let them do it.

We would be happy to try to develop large-scale photovoltaic projects without the need for rebates, etc. if we knew who our customer was. If I could go to a utility and I knew they would be willing to buy large amounts of solar at a specified price, then it is up to me to figure out

is there a way I can build that project and meet that price with just the tax incentives.

The other thing, of course, utility ownership doesn't make any sense for most renewables because they can't take advantage of the tax incentives.

I know that is sort all over the map, but I mean, I don't see how in the world the state is going to meet the RPS standards by 2010. That doesn't make any sense at all given where we are at and what has not happened over the last five, or ten, or fifteen years to move these industries ahead.

With that, I will stop talking.

PRESIDING MEMBER GEESMAN: Thanks, Vince.

COMMISSIONER BOYD: Vince, I think you hit a lot of nails on the head there, but the economic hurdle is historically has been "the hurdle" that renewables have faced all my working life in Sacramento which goes way beyond the Energy Commission.

Do you think the climate is different today than it has been in the past such that we can successfully clear that hurdle now, and is it

just talking to the industry that gives us the input on the economics, or is it something bigger than that?

MR. SCHWENT: Is the climate different? That's a very good question. In the early 80's we had an energy crisis, and we responded with standard offer contracts, and things happened, at least in the wind industry they happened.

There are half a dozen books on the market right now all predicting the coming end of the oil era, that the demand is about to exceed supply. If we are in that position again, and the state is able to look at what the future price of fossil fuels is going to be, and by your own admission every time you make an estimate, you know, you can easily be off by 100 percent.

If the state was willing to make aggressive estimates to where fossil fuel prices are and then implement public policy based on that in the forms of standard offers or whatever that are pegged to where fossil fuel is going to be, not where it was last year or where we thought it was going to be last year if we might have a chance.

COMMISSIONER BOYD: Thank you.

MR. SIMONS: Thanks. Representing the Biomass Energy Alliance is Julee Malinouski-Ball.

MS. MALINOUSKI-BALL: Hi, thank you. I am Julee Malinouski-Ball on behalf of the California Biomass Energy Alliance. Actually, we don't disagree with probably anything that CA SEIA just said. Given that, we actually would like to commend Bryan Jenkins and his team on his numbers and his analysis, they look pretty good to us.

In fact, we are actually really anxious to see the much larger report that is out in draft on the Biomass Collaborative's website right now. We are busily going through that, and we are going to provide comment. The industry in that instance is probably very much engaged in what comes out of that report.

Given that, though, we do have only just a few comments on the numbers that we have seen, you know, is there sufficient renewable resources, and of course the answer is a resounding, yes. What this report doesn't ask and it does hint at, and you have hinted at it as well is we are actually worried about the short term and losing baseline.

We are worried about plants closing, so

this is a reality for the biomass industry. We are not so sure about the others, but the pressure that does put on the other industries is you need to make up the difference. If you are losing one renewable to whatever economic crisis is facing us, the other renewables need to pick up where we are leaving off.

If the goal on the other hand is development of all renewables and increasing all renewables that we need to face this looming crisis for the biomass industry.

PRESIDING MEMBER GEESMAN: Thanks, Julie.

MR. SIMONS: I want to make a couple --

PRESIDING MEMBER GEESMAN: Question for you, George.

MR. MUNSON: (Inaudible).

PRESIDING MEMBER GEESMAN: Come up to the mike, Steve. Make sure your green light is turned on.

MR. MUNSON: I am Steve Munson, Vulcan Power. We didn't have a geothermal representative, Ted Clutter couldn't be here today. I'd like to make a couple of comments on questions that are on the list and questions that

were raised.

With respect to procurement and the question was raised what have we perhaps as regulators done wrong. Our company has been, Vulcan Power has been involved in multiple contract negotiations over the past two years.

It is our observation that with Southern California Edison contracts which have been announced, that many good things came of that very very difficult process. There was a lot of give and take back and forth between our company and the utility.

We came up with a contract that is probably fair on both sides. That particular contract, and of course, I can't get into it here, it is still up for review and final approval I hope, but that contract came up with one thing that is very vexing point of contention now and other contracts that we are involved in. That is what a fair performance bond, and any of the other development bond amount really ought to be, what is fair to the utility, what is fair to the developer.

We haven't got that resolved in the other contract arrangements, and I think that if

the regulators could look at maybe those initial round of contracts that are coming through and looking at them with one eye on the wind intermittent type contracts and one on the base load type contracts, maybe you could find a standard contract there like ISO 4 to guide others.

I am very concerned. It is a little late in the process for the RPS contracts are being negotiated now, but there are things going on in those contracts that I don't think are fair to the developers and very painful difficult issues to deal with.

My second comment would be that when you run a study, you should know exactly who it is that are trying the study. If you ask a geothermal company to do a study on geothermal resources whose business is providing reports to banks about existing amounts of steam in the ground on which those banks are going to loan money, then you get one report. The report is focused on existing resources, which has facility because it does show you where you might expand from existing proven properties, but it doesn't do a darn thing for the exploration plays.

It doesn't do anything for bringing the volcanic systems on line in the United States. Japan has 500 MW of geothermal, it is almost all on volcanoes, there is 4000 MW worldwide that comes from volcanoes, and unless we get a little different view of the exploration plays at various companies are willing to expend their own money on, then we are going to miss the volcanoes again in the United States, and we will miss some really good resources for California.

I don't know how many meetings now I have had with staff and my whole team is just a little disgusted with the process. We now have a geothermal report that leaves some known good exploration plays out because of the sieves that they put the analysis through. I think there are going to be contracts signed on properties that aren't even listed in the California Energy Geothermal Commission Study. I am sorry to bring it up, but we've tried and tried and tried and just weren't getting anywhere.

(Phone noise interruption).

COMMISSIONER BOYD: Just keep talking over it, it will drown them out I think.

MR. MUNSON: I guess he is taking a

phone call.

PRESIDING MEMBER GEESMAN: Right.

MR. MUNSON: Hello?

PRESIDING MEMBER GEESMAN: Why don't we cut the phone off.

MR. SIMONS: Yeah, go ahead and cut the phone.

PRESIDING MEMBER GEESMAN: Go ahead, Steve.

MR. MUNSON: The other point that.

PRESIDING MEMBER GEESMAN: Let's cut the phone line off.

MR. MUNSON: Hello?

PRESIDING MEMBER GEESMAN: Okay.

COMMISSIONER BOYD: Maybe not okay.

PRESIDING MEMBER GEESMAN: Is there anybody in the room that knows how to cut the phone off? Try again, Steve.

MR. MUNSON: The third point that I would like to make, I'd like to respond to question seven through twelve with one request. I would request that the regulators establish with developers at least one more geothermal and working group on transmission.

We have asked for it for six months now.

Maybe our company just needs to set up a meeting and invite everyone to come, you know, ya'll come, but we believe that there are constraints that have existed on the system. We have listed them, north (indiscernible), north of Cottonwood, north of Brown Mountain, the Cal/Oregon border, and what to do about the Pacific DC inter tie line. Those are all issues that ought to be dealt with cooperatively between the developers and the utilities and the CAL ISO. We would ask for those working groups, and I think that would get us way down the road on Item 7 through 12, and I appreciate the opportunity to speak again.

PRESIDING MEMBER GEESMAN: Thanks, Steve.

MR. SIMONS: Based on some of the input that we've had, again, I really viewed the morning session as pretty much vanilla stuff. There is not anything new here that people haven't seen, and I agree with a lot of the comments about why aren't we getting on with it.

To get on with it, I think some of the questions that we have to pose, and, again, we will hear this in the afternoon, we intend to have Dan Adler who is with the PUC, you know, the panel

in the afternoon, but what I've seen is we begin to march down the RPS pathway, there are some critical questions that we have to ask, and I think there is an analytical background to that.

You know, if we are going to, regardless if we mandate or incentivize, or whatever we are going to do, we really have to know that the resources are there to answer some critical questions, in particular, how do we capture the importance of the problem areas that we see happening in the grid as we go out in the future.

We know that there are more congested and more capacity constraint areas in the transmission distribution system. How do we do an RPS that allows renewables to better address those hotspots within the system. I think there is an analytical piece there that is going to be important in terms of providing the utilities the capability to really target what they want to do in the RPS.

How do we gear solicitations to obtaining a portfolio of renewables that can better meet the demand profile. It is one thing to talk about wind as intermittent. It is another thing for us to say, okay, so how can we assemble,

if we have a rich rich state of renewables, how can we better assemble these pieces to better meet demand load profile.

Can we do that, can we do it at the appropriate cost? That really begs the questions of what is the interplay of the economics of putting in new conventional fossil units, upgrading the T & D system, and bringing on line new renewables.

In order to really answer those in some fashion that is useful in the RPS solicitations, again, I think there is an analytical piece that needs to be addressed there.

With that, I would like to go ahead and ask the panel to really provide us some guidance on if we are going down the RPS solicitation pathways that we've been going on, what additional analysis would you say would be useful for us to put together that type of a structure.

If I am at an IOU, and I am looking at do I just simply say, I want 200 MW, I don't care what it is, if it is wind, or do I really want to say I want 200 MW or 1000 MW that provides me with this cost, meets this demand profile, and is located at these systems within my transmission

distribution system. I think that is a lot more powerful. So, really the question is, what kind of additional work do you see us doing to bring that type of information to the forefront, and is that the right path, or should we forget all of that. Forget all of the analytical work, and as Vince suggests, just get on with it.

Maybe we can just go down through the panel and get some responses to that starting with Robert Anderson.

MR. ANDERSON: Thanks. We will take the question back, and probably provide some written response. Just a couple of thoughts quickly off the top of my head. One of the issues that we found particularly in our last RFP is working through the transmission issue, and I won't have these proceedings correctly exactly right, but we had previously asked for transmission studies, if you've got potential projects, if you have ideas of where they may be, let us know way in advance, we did transmission studies for those areas.

When we actually ran the RFP, we actually got no bids from any of the areas that were previously specified and all of our bids were now in new areas. So, we basically had to throw

out all the old transmission work and redo it.

It is a little bit the industry working with the utilities. Let's identify those main areas so we can get the transmission work done way ahead of time, that will greatly speed things up.

Can the CEC really help on that? I am not sure, a lot of these are very detailed utility specific studies, so I am not sure the CEC can really help on that, but one of the areas that I think would really help move the process through a lot is let's just identify these areas in the past where the renewables are going to be, so we can get that transmission work done.

MR. SIMONS: Thank you. Hal, any comments?

MR. LAFLASH: You can do all kinds of studies, but I'm not certain that it gets back to Gary's point about is this a regulated market or a market responsive. You can do all of these studies, but there is going to have to be a market that responds to that, which is Rob's point that the market moves around alot. It is kind of hard to say where it is going to be a couple of years out, as he found out in his RFO.

We do think there is a need for more

analysis, and you are doing some of it here. Tomorrow is an integration workshop, and I think there will be important learnings coming out of that. We would like to see things that look more at the utilities needs, least cost/best fit part of it, and part of that is location, but a lot of that is profile, does it meet your needs, does it provide firm capacity.

I don't know that you need a whole lot of analysis on that, I think we know a lot of those answers. I think the integration work going on tomorrow and following workshops will be useful, though.

MR. SIMONS: Thank you. Gary.

MR. ALLEN: If I understand the question and I am trying to get a broad perspective on the question, it is how do we get more renewables today instantly if you will. I think there is an easy answer to that, you can say we will take any renewable that is brought to us at any cost.

As long as you want to constrain the renewables by those that are economic, then I think you are going to run into some issues. Some of these issues we have discussed already. I'll try to remind the Commissioners and others that we

set prices and standard offer 4, and we were able to expand the renewables substantially during the late '80's, but it was at a tremendous cost to the ratepayers. You know, we finally emerged out of that, and you can't say with assurity what the gas price, natural gas price will be three, five, ten years from now. Are you going to be right, or are you going to be wrong.

You will undoubtedly be inaccurate in your forecast. The question is will you be 20, 30, 40 percent too high on your estimate, or will you be 20 or 30 or 40 percent too low. Will gas prices be $3.00 or will they be $8.00? As we all know, it is a market, and we will have to just see what merges from that.

PRESIDING MEMBER GEESMAN: I reflect upon the time that it took to get the Mountain View facility through the regulatory process based on the cost to generation study we did in our 2003 IEPR, 70 percent of the life cycle cost of that facility or the electricity generated from that facility will be fuel cost.

Now, I don't know what estimate your company had made of the fuel cost when that project rushed through the regulatory system, but

just given the time when the regulatory approvals were given, I would expect it very comparable to the gas price forecast that this Commission adopted in its 2003 IEPR cycle. We expected natural gas prices to stay in the $3.00 to $3.50 range for the remainder of the decade. We were wrong, all of us were wrong.

As it relates to that particular project, that's 70 percent of the costs to your customers being reflected by that wrong fuel estimate. In evaluating the importance of our cost assumptions for these renewable solicitations, I think we have to have a certain amount of humility about how wrong we've been and how wrong we are likely to be and try to make some judgements as to what a prudent approach to risk management would be.

I think much of that thinking underlies the state's desire to achieve a 20 percent RPS target. We have left a fair amount of discretion in the hands of the utilities as to how best to go about doing that, what types of resources should be brought on line.

I have to say again, if we appear to be falling significantly short of those targets,

there will be considerable regulatory frustration with that, and we need to figure out a way to get back on track. My sense right now is that we may very well be falling short.

MR. ANDERS: I don't have any specific comments on that question.

MR. SIMONS: Nancy.

MS. RADER: Okay, in terms of I think George your question was should the utilities go out and say we want this or we want that. I think the least cost/ best fit approach was one that we supported because we saw it removing some of the utility bias like we just heard from one of the utilities say we need firm capacity, meaning we need firm renewables capacity.

The least cost/best fit approach, the idea of that is if in that analysis, it turns out that wind and a dispatchable fossil fuel resource together are lower cost than a firm renewable, then you go with the wind. The methodology works if it is allowed to work, and if biases aren't introduced.

I think the Commission is doing what it needs to do to compliment that process in terms of coming up with our integration cost adders, which

the Commission is doing, and I hope we are going to see soon the analysis of the impact of the full Tehachapi resource on the transmission system because we need to understand so the utilities are comfortable or more comfortable building into that resource and accepting those bids.

Where least cost/best fit approach doesn't address unique benefits like the benefits of the biomass industry provides, I think we need complimentary approaches to shore up our baseline, like expanding the Tier 1 subsidy to capture those benefits.

Some of the other points that have been raised I wanted to respond to also, in terms of utility equity in wind plants at least, utility ownership is not necessary to capture the tax benefits, and it is not necessary to raise capital. All you need is a good contract to do that.

We think that introducing utility ownership at this time is just going to complicate the process and make it more contentious.

In terms of the standard contracts, CA WEA was a big supporter of standardizing much of the contracts. We were not successful at the PUC,

they chose to do virtually no standardization, and I think part of the reason that we ended up in these long negotiations was the complexity of those contracts and the fact that so many of the terms had to be negotiated.

That said, however, I think the utilities have learned from that process and now see that a lot of these terms were erroneous and that are being more reasonable on them, I think there is room for improvement in the Mexico round. In particular, I think the utilities need to accept more of the risk that may be introduced by a new market structure. They are in a much better position to accept that risk.

I think that if the terms are improved, standardization is less important, and I hope we see some improvement, and I hope we see a little bit more PUC pro-active action on that issue.

I do like Vince's suggestion of a standard offer 4 type of approach, and as you suggested Commissioner Geesman, I think we can easily forecast a reasonable fixed rate. We have learned from our SO 4 era, and I think we could, for example, if we don't make a lot of progress in the very near term, issue some standard contracts

at the MPR and let's see what the developers can do because I think it is going far too slowly right now.

MR. SIMONS: Vince.

MR. SCHWENT: Nancy just reminded me of something historically. The old SO 4 contracts when they first came out in the early 1980's provided for payments that would eventually reach as high as 15 cents a KWh based on the forecast at that time. I am going to guess in most wind developers would be delighted if they could go in and sign a fixed price contract for 5 to 10 cents.

Again, we know enough. In response to George's question if I got it right, George, about trying to do some more analysis to find a better fit between renewables and utilities, what we are talking about is increasing renewable usage in California by 9 or 10 percent, going from 10 or 11 to 20 percent.

At those penetration levels, quite frankly, I don't think it matters, just get it on line, get the next 10 percent renewables on line. I don't care whether it is base load or peaking or whatever. Doing that is going to vitalize these industries. It is going to get economies of

scale.

If we were talking about 30 or 40 or 50 percent of penetration renewables, then clearly we need to worry more about what is base load, what is firm, and what is not firm, but the next 10 percent, that is not a relevant question. Just get it done because right now, yeah, with the process that has been started with utilities getting to do the RFP's, it is absolutely predictable that they are going to push all of the risk onto the developer, all of the risk onto the proposer, and there is going to be a very slow start to actually getting anything put on the ground.

MS. MALINOUSKI-BALL: I think one of the questions that George was asking was what further analysis would be valuable, if not for the resource adequacy, and I think a lot of analysis has been done on renewables. I think we have seen that every where you see, we need long term fixed price contracts. We need to sustain the PGC fund, if not increase it.

We need to look at more opportunities for like the biomass to energy grant program that helped to divert ag waste from open field burning.

We know what these things mean to the industry. One thing I'd like to see an analysis on personally is, you know, a biomass component in the RPS.

If you look at how much biomass power costs compared to wind power -- I know you are shaking your head -- biomass power compared to wind power, you know, it is difficult for the biomass industry to compete at those levels. If we have a biomass component to the RPS, you know, what would it look like, what would we need to realize that. I would have more questions to ask having thought about it more, but that is kind of one analysis I'd like to look at.

In that, you would actually kind of enumerate the social and the environmental benefits of this type of power, you know, in terms of waste management, compliance for landfill diversion diverting ag waste from being burned, forest management practices, etc.

MR. SIMONS: Tod. I was going to -- just before you start, Tod, were you going to make comments specific to geothermal to kind of round out the panel?

MR. O'CONNOR: No, I'm not.

MR. SIMONS: Okay. I was going to suggest you the rest of the questions are more relevant for this afternoon's panel, and maybe it is time to go ahead and open it up to general questions. Again, I would like to thank all of the panel members for coming here, providing us feedback. I think it is extremely important, and again, I thank you very much. Go ahead, Tod.

MR. O'CONNOR: Thank you, George. Good morning, Commissioners. My name is Tod O'Connor. While I am covering this hearing, this important workshop for a renewable client, my perspective on George's questions and some of the input comes from a personal experience of trying to find financing for solar, and I don't have a solar client here, so this is just based on my experience over the past ten years.

I would like to go to the conclusion page of your solar presentation and suggest that the customer classes be expanded from two to four. You mentioned residential rooftop PV and commercial rooftop PV. While I understand the public policy for putting those two down because of the movement of SB 1. In order to get to fully answer your questions on 1 and 2 about California

having adequate resources available by 2010 and 2017, I had to take a look at the potential application for institutional end use customers, and with that, I mean schools.

In the 1980's and the 1990's, the investor owned utilities using ratepayer funded R & D dollars looked at schools to deploy solar in those areas where there were growth population areas as a way of deferring T & D costs and reducing capital investment.

I would tend to say that the use of schools on where there is solar especially in those areas of California where there is a population growth, what with the needs of the population, especially during peak time, I would strip the ability of the local distribution system to meet those needs could be supplemented by the strategic use of solar on rooftops of 15 KW, 200 KW, depending on the size of the schools in the system.

Also it is one of these policies that the state mandates, but the state ought to step up and play as well. With the number of universities and colleges available in those areas where it makes sense to deploy solar or geothermal or steam

in order to meet these mandates, and it is quite possible that they need to come up with a procurement plan or an ownership plan that can help meet these goals. That is the basis of my comments. Thank you.

PRESIDING MEMBER GEESMAN: Yeah, I would say to that ironically, some of the water districts have been among the most aggressive public sector actors in photovoltaic area, and I think there is probably a lesson there that public entities with access to long term tax exempt interest rates seem to be a pretty good match to this technology.

MR. SIMONS: Steve?

MR. MUNSON: This is Steve Munson, Vulcan Power. We all know that ISO 4 is not only a continuous term, it created problems for both the development side and the utilities, but you know, we could have a program in this state that would be a standard offer 4 contract in the sense that most of the conditions are worked out by the regulatory authorities and the developers could compete on price.

We all realize what happened with the ISO 4, but you know, it wasn't all negative. By

charging high prices for renewables, we got a lot of technology built and the prices are now down for all the renewables, and that is a very good thing.

If we had SO 4 type contract that would establish fair performance guarantees, those things are really continuous, and maybe there is some learning curve that we went up with the initial SCE contract.

The other point I would make is as we think about what pricing might look like, we should remember particularly within renewable, different types of resources and different development stage resources have different costs, and therefore, will have different prices. One size won't fit all.

In fact, we as a company disagree very much with some of the pricing signals economic signals we are getting on this program because it is fairly well known that a number of the resources in Nevada are cheaper than the Imperial Valley type projects or can be, and this is not to open a line of argument with anybody, it is just that they have to deal with high blind resources in the Imperial Valley at some sites. So, one

size won't fit all.

There is one thing that we think the state is missing in the biomass sector. We have a biomass project. There is $760 million of healthy forest initiative money projected to come to get phased up to that amount in four to ten years. That is designed to thin the forest and small diameter trees, reduce fire threats, and create healthy forests, and create jobs and real communities.

I believe there needs to be a coordinated program through the CEC probably to see that a lot of those funds come to California and to push for those funds. Then I think you would see biomass grow, at least in the forest sector.

Thank you again for the comment.

PRESIDING MEMBER GEESMAN: Thanks, Steve.

MS. APRICOT-ECKBERG: Good afternoon. My name is Hannah Apricot-Eckberg, and I am here as a member of the public. I am up from Santa Barbara who is very familiar with the different issues dealing with energy, especially with the constant threat of oil drilling of our coastline.

We have in fact adopted a goal of going fossil fuel free by 2003 and are really looking hard to investigate how to incorporate as many different alternative energies as possible.

I just want to emphasize how important this is at the individual and local level and as you continue through this process to really remember how you can best support the smaller efforts at the individual levels of both communities and specific households to be able to incorporate as many alternative energies as possible and to really strive high and reach the highest goals that you can for what is best for all and not just the bottom line of the different companies as you are adopting this motto of least cost/best fit. Let's really not just get caught in the bureaucratic tape and just thinking of cost. Let's look forward to the future and see how we can take very important steps now to incorporate all of these different energy policies.

Thank you for your work.

PRESIDING MEMBER GEESMAN: Thanks for your comment.

MR. ROMANOWITZ: Hal Romanowitz, Oak

Creek Energy. We control approximately 15 to 20 percent of the plausible Tehachapi developable resource. We have yet to bid into any of the RFO's primarily because of the terms and conditions that were imposed on them and that we took seriously the inquiry or the specifications of the bids and because of the transmission constraints, basically, you couldn't legitimately bid into the RFO's that were out.

If you will note the awards that SCE made in this last round, the great majority of that award is that they -- in other words, essentially, stretched the offers that went in, gave options and so on to completely non-conforming bids to the RFO's so that there is a big issue of are these RFO's going to be taken seriously. Are deposits meaningful? Are you going to squeeze the developers super hard to make it very very difficult and risky to bid, or are you going to sort of level the playing field, have decent terms and conditions as Cal WEA has been trying to get so that you can have a truly competitive bid process and make the process go forward smoothly?

There is a lot of resource there, but

you I think need to make the process work.

PRESIDING MEMBER GEESMAN: Thank you, Hal. I guess I should say my colleagues and I have a fair amount of frustration with the PRG system that has been utilized in these bidding processes. None of us have signed a confidentiality agreement, so we only hear second hand about the solicitations and about the results.

Your comments are pretty disturbing, and I think add to a growing frustration of how these procurement cycles are managed.

MR. ROMANOWITZ: Yeah, I personally am one who has argued very strongly for openness. The process is just the opposite. It is an extremely closed process. Our company being relatively small has become a member of essentially every entity along the way so that we could participate in this process in an open manor, and it has been extremely difficult to do so.

We are a member of WECC and just about every organization. We spend a lot of time participating, trying to make this thing work, and it is extremely difficult. The SO process is one

that at least you get things on the table, you allow a much more relaxed process, people can organize their bids, get them in, whereas today, you have processes that trigger in 30 days on a surprise notice, and how are you going to get a reasonable responsive bid in on that with the risks and terms and conditions that apply.

It is an extremely difficult and nearly unworkable process for most entities to bid in a meaningful way, and there are a lot of resources out there. There are resources that can be very reasonably priced, and instead, you are forcing the price up and making bids very difficult. I would really encourage it.

Of course, my other pet peeve is the storage issue. We talk about the intermittency of wind. We have good storage that we can bring with the wind, yet the whole process in non-workable to make it happen. We have, I think we can make very serious very high quality bids into the process if the rules had a reasonable amount of flexibility and would allow things to happen. It is extremely frustrating to us to see how it goes.

PRESIDING MEMBER GEESMAN: Thank you for your comment.

MR. ALLEN: I don't even know how to respond, but I have to object to Mr. Romanowitz's characterization of our process. We had 53 some bidders, and we wound up with six winning bidders, none of them have complained or found objectionable our process.

PRESIDING MEMBER GEESMAN: Winners seldom do.

MR. ALLEN: None of the losers, none of the 53.

PRESIDING MEMBER GEESMAN: None of the 53.

MR. ALLEN: None of the 53. Mr. Romanowitz did not bid into our solicitation. He did not participate. I admit the filings are confidential, but he really has no basis on which he is making his statements.

PRESIDING MEMBER GEESMAN: Yeah, it was that the confidential that I was focused on. I think we have expressed several times in the past frustration with the fact that procurement is not a more open and transparent process subject to public scrutiny. For those of us who have not signed confidentiality agreements and have a public responsibilities that from prevent us from

signing such agreements. It is really an increasingly untenable set of circumstances.

When we hear comments like Mr. Romanowitz's or when we observe in your company's instance, nineteen months spent to produce 142 MWs. I acknowledge that you say there are options associated with that, that could carry that number up to 420, but at the lower number, that is 8 or 9 MW a month, triple it to 420, it is still about 25 MW a month. We are not going to get to where we want to be at that pace, and I think that the state needs a procurement process that is subject to a little more public confidence if we are going to achieve our goals.

I can't comment on any of the specifics in your solicitation because as I said, I am not privy to them.

MR. ALLEN: I will respond once again to your 8 MWs a month. Much of that time was transitioning not only our own organization but also our management from a standard offer mentality into a current market design mentality, and there is a vast difference between the two. I defy anyone to look at the ISO and say differently.

PRESIDING MEMBER GEESMAN: I was impressed by the velocity with which your management was able to come to grips with those challenges in its review of the Mountain View Project, and I think that is the standard by which the RPS procurement should be evaluated. Comparable level of urgency.

MR. ALLEN: The difference that I will suggest is you are looking at nearly must take energy as renewable turns out to be versus dispatchable, economically dispatchable resource that is available mostly for a capacity resource.

PRESIDING MEMBER GEESMAN: With 70 percent of the cost being direct fuel cost past through to the customer at levels that nobody has a good prediction of what they will be.

MR. ALLEN: And all of the cost will be past through to the customers for the renewables.

PRESIDING MEMBER GEESMAN: But those are fixed costs for the most part. I can bound a capital cost in a way in which I have no idea how to bound a fuel cost.

MR. ALLEN: The premise is that they are capped or floored by the NPR, and so you're ultimately come back to a gas based premise in

either case.

PRESIDING MEMBER GEESMAN: Jane.

MS. TURNBULL: Thank you, Mr. Geesman. I am Jane Turnbull, I am here for the League of Women Voters for California, and I have two points.

I can concur with a lot of the comments that I've heard from the panel. I also concur with Mr. Geesman's comments, Commissioner Geesman's comments about the fact that the cost of procuring renewables is taking a lot longer than we had expected.

The League does support renewables and conservation. We have for 25 years, and we will probably continue for the next 25 years. On the other hand, I don't think that this morning's presentation really is adding a great deal to what we already know, and that is that there are a lot of renewables in this state, but it is the process in terms of how we are going to get them.

I think when the PV zealots around this state get the numbers that came out this morning, they are going to start blaming again, and the utilities are going to be taking that blame. The Commission is going to be taking that blame, the

PUC is going to be taking that blame, and so is the industry.

I don't think we really need to be in a blaming kind of mode. I think actually the suggestion of a standard offer contract is really quite exciting. I did take a look at the RFP that just come out from SCE, and I was totally intimidated. I flipped pages and this was just incredible. That is not the way to go.

I do think this state paid a penalty in terms of standard offer 4 contracts. As I recall back in the late 80's maybe about 1990, PG & E was paying a premium of about $250 million a year to the contract holders of standard offer contracts. That is a lot of money, but at this time, I think we ought to start taking a look in terms of what we are paying as a state in terms of other incentives for renewables and decide whether those incentive programs are the best way to go.

I personally, and I am not speaking for the League, but I am rather concerned by SB 1 with the incentives that would go if that bill was passed and the amount of money would come out of other budgets in the state.

I think perhaps what a good analysis

might look like at this point is to look at the totality of the incentive programs that are out there for renewables and what replacing those with something like a standard offer contract would look like. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Jane. Other comments from the audience.

MR. MYERS: Good morning, almost good afternoon. I am Sarah Myers with the Center for Energy Efficiency and Renewable Technologies. George asked about another study that could be done. CERT has spent a lot of time, a lot like Hal described trying to be in every venue that this complex law is visited upon and its implementation.

I commend back to the Energy Commission and every other state agency that is involved in implementation of this law to work again on coordinating that implementation.

At the outset, there was a collaborative study planned or a work plan between the staffs of the Energy Commission and the PUC, and it had a timeline. Timelines are good things, we think targets are too. Matching up reality with time is also very good, that implementation plan went

forward, and in its first year, the agencies largely met the deadlines that were set.

It has kind of gone away, that coordination seems to be missing, and yet we need it just as much now as we did then. We have had at this point only two RPS qualified solicitations, the 2003 Edison solicitation was an interim authority.

We have had results or contracts from one, and the law has been in effect since September 2002. So, I think, wow, buyers and sellers of this power or obviously involved in this to the hilt. I think the regulatory agencies play a huge role in making sure these deadlines are met.

I ask that the Energy Commission and the PUC try to bring the CA ISO into this dialogue, try to have a kind of new energy action plan which includes them to set target because you heard today transmission is a huge hinderance to meeting these goals. We worked hard as an organization to participate in the Tehachapi study group, salt and sea study group. Perhaps we need a new geothermal study group. These are all fine, but you do need that statewide effort to bring in those results

and get a plan for moving forward.

We do appreciate Edison's petition to FERC, we supported it as well to try to resolve the nuances of financing transmission. There are it seems like every time we move forward, there are many reasons to take some steps back, but I encourage you again to look at a collaborative process of regulatory agencies as a way to continue to move forward. Thank you.

PRESIDING MEMBER GEESMAN: I think that is a good suggestion, Sarah.

MR. SIMONS: Well, I want to thank everybody. I think we have very seriously excellent input to this. Again, I am surprised at the number of people who showed up today. As I mentioned, this was pretty vanilla stuff to me. It is very nice that this amount of people showed up because, again, there is a very high level of interest of how we are going to move down the RPS.

I think at the staff level, we really have to look at, you know, does this mean anything, or a couple of comments we are not bringing much to the table with technical potential. I agree with that assessment, I don't think this has added much to it. I do think there

is some analytical work that will help in the future.

I am certainly not a policy person, so I can't comment on the policies, but I think I've heard a lot of very targeted and very valuable input to where we should be addressing our efforts.

I want to thank everybody. We are going to have an afternoon session that will start at 1:10. We will break for lunch, and then we will meet back here in the afternoon to go over interstate renewables. Thank you very much.

(Thereupon, at 12:06 p.m., the workshop was adjourned, to reconvene at 1:10 p.m., this same day.)

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AFTERNOON SESSION

1:10 p.m.

MR. SIMONS: We are reconvening of the Integrated Energy Policy Report Workshop on renewables from outside of California. In state, we covered in state renewables this morning.

This afternoon we are going to switch gears and talk about renewable resources inside the WECC states and the challenges and issues faced with transferring those into California.

We are going to start off with have Ray Dracker from the Center for Resource Solutions talk about renewable resources in the WECC.

MR. DRACKER: Thank you, George. In this afternoon's session, we are going to hear a number of speakers speak on various technical issues having to do with characterization of renewable energy resource along with some transmission issues.

We are going to touch on transmission issues this afternoon a bit more than we did this morning. One of the things I wanted to preface all of this work that you are going to see, the analysis that we are going to show does not represent a comprehensive assessment of the

renewable resource in terms of detailed geography and transmission interconnectivity, and most important as it was touched on this morning, the relative economics of these options.

The transmission analysis that we are going to show is not representative of the best or only transmission solutions, but we thought this topic was an important one for the state to get started thinking about and so we wanted to bring forth some representative information so that we could speak more than in the abstract in an attempt to stimulate some creative thinking on this subject, which again, I think is an important one, particularly as we look perhaps in the future beyond this short term RPS goals.

Again the first question one might ask is why consider renewable resources outside of California. We heard this morning that there is a very large high quality renewable resource within this state. We are blessed with the right mix of geography and latitude and longitude and we have almost a unique situation in the world where we have vast quantities of renewable resource very close to large quantities of people and load centers.

I think it was illustrated this morning that the resource we have inside this state is largely sufficient to satisfy our near term RPS goals, 20 percent either by 2017 or perhaps 2010.

Obviously there are severe transmission challenges independent of renewable energy and certainly as you overlay intermittent renewables on a transmission system that is overly constrained already. The situation with transmission system suggest that we try to do all we can to exploit the renewable resource close to our indigenous load centers.

Of course, renewable energy development inside of California will bring local economic development, and that is going to be valuable and important. All of these things suggest that we do the best we can to exploit the indigenous renewable resource within the state.

However, just as we haven't relied exclusively on California hydro power, California nuclear power, California coal power to serve the state's needs, I think it behooves us to consider renewable energy outside of the state as well.

I know most of the folks in the development community and the utilities are

concerning themselves mostly with the short term needs to get procurement rolling and to get our 20 percent targets met by 2010, and that is a challenge. We are also at the same time considering policy decisions that hopefully will take us to a more aggressive renewable portfolio standard looking at something like a 30 or 33 percent RPS will require an additional 7,000 to 15,000 MW of renewable energy above and beyond what the 20 percent RPS target will take us to.

There was a lot of discussion this morning about gas prices and how high they seem to have stayed and the fact that perhaps renewable energy is an economically interesting choice compared to gas combined cycle independent of any kind of mandates.

In addition, we have a series of greenhouse gas emission targets that the state has considered, so I think to avail ourselves of as many renewable energy options to perhaps even consider going beyond a RPS is an important policy direction.

Setting that aside, just availing ourselves here in California to a more robust supply side of generation options just makes for a

more healthier market, so I think to the extent that we can bring a viable consideration of out of state resources into the market in the short term, or particularly in the long term, will just make for a healthier market.

As you look at the characteristics of the renewable resource, to the extent you can create a geographical diversity in that renewable mix which can create maybe a more attractive production profile portfolio, that also would have benefit, and that is more of an issue in the wind area than compared to say geothermal or solar.

We are going to have Ryan Wiser speak a little bit later about some of the production profile issues concerning wind energy. So, those are some of the reasons why I think it might be valuable as we sit here today to start considering out of state renewable resources, in spite of what we heard this morning which is we have a very great quality robust supply in state.

Let's take a look at some of our neighboring states around the west. For the past several months, CEC staff has done an updated assessment of the outlook for renewable generation throughout the west. There are many policy

drivers in other states that are pushing for more renewable energy, and as we alluded to many times, sheer economics drives to more renewable energy.

CEC took a look at what kinds of RPS programs are moving forward in various western states, what kinds of IRP processes are driving utilities to include greater and greater quantities of renewable energy in their mixes, plus just the general efforts of renewable energy development community to promote projects throughout the west has caused a fair amount of additional renewables to get on the development table throughout the west, and you can kind of take a look at what the numbers are looking like.

Still, the demand in California is large compared to the rest of the west, but in aggregate the demand through the rest of the west is quite large.

Just a quick look at those numbers, though, and you could see that roughly speaking, each of these states has about a need for about 1,000 MW of new renewable energy give or take a few hundred MWs over the next decade.

Now let's look at what the demand for renewable energy will be as opposed to the

resource, and we heard this morning that, gee, it is not a whole lot useful to look at technical potential numbers that are so large without consideration of supply side issues, economics, and transmission, but let me just kick back to these technical potential numbers.

Once again, these are numbers derived from the renewable energy atlas of the west that was published a couple of years ago, and these are actually numbers that I selectively excerpt from the CEC or the ER report from 2003, I just pulled them out by technology in select states.

You can see just looking at the wind potential alone, there are 20 or so GW in each of the states that are immediately neighbors to California: Oregon, Nevada, up north in Washington, and then across in New Mexico. Again, that contrasts with about a 1 GW each of demand in those states over the next decade.

As you move further west onto the Rockies and the Northern Rockies, the numbers go off the chart high, almost as big as some of the solar technical potential numbers we saw earlier. The resource is quite vast and within that resource, we believe there is a kernel of very

attractive, very economically attractive resource.

At the CEC within Drake Johnson's renewable program along within George Simon's PIER program along with work at NREL and LBL, we have begun to look at what the supply curves look like for these technologies, what the economics are looking like, and as George mentioned, in a month or so, we are going to have a workshop that is going to focus more on economics, but I think the elements are there to begin to get into how much of this resource is economically interesting to us.

A quick look at the geothermal potential in the neighboring states. There are several thousand GW in each of Nevada, and that is reasonably well characterized. We are going to hear a bit more about that a little bit later as well as a sizeable resource in Oregon and then in Utah as well.

With geothermal and wind resource, it is quite large throughout the west. I don't want to speak too much to the solar resource, we saw we almost have an unlimited supply both defuse and high quality DNI resource throughout California, but in the neighboring states of Nevada and

Arizona, there is an incredibly vast solar resource as well.

Just switch gears for a minute. There are as the energy marketplace was sort of taken apart in the 1990's and we are kind of putting it back together almost as we speak, the whole notion of integrated transmission and resource planning sort of went out the window in the 90's, and now it is coming back here at the CEC as well as CA ISO, we are trying to get to doing a much better job at that, but there are numerous regional studies going on throughout the west that are looking at regional transmission issues.

They are trying the best they can to integrate resource considerations with that, and they are trying to evaluate interregional exchanges. Here are four major assessments that are ongoing: the Northwest Transmission Assessment Committee, the Rocky Mountain Area Transmission, Southwest Transmission Expansion Plan, and the Southwest Area Transmission Study.

Each of these regional assessments are looking at regional transmission issues as it relates to resources and almost without exception, all of these studies have an element that is

looking at a renewable energy resource and the potential ability to export that into California.

I thought that was rather interesting and telling. It suggests that a lot of folks in the region are interested in gaining access to our market given its size and the relative lucrativeness of it.

It also seemed as I kind of tried to understand what these studies were doing, for the most part, and I don't want to say because there are participation by folks from CA ISO and some of these studies and other things, but for the most part, there are many plans developing to move renewable energy into California without much considerations of what we think here in California, and I think that is something I would like to see change.

The Northwest Transmission Assessment Committee looking at the Pacific Northwest and into British Columbia and Alberta. He is just a quick look. They are looking at wind resources wherever they can, a lot of coal in the Rocky Mountains, some gas in the Northwest, and some hydro up in Canada. Again, there is now an element that they are looking at exporting some of

this power into California markets.

A look at the Rocky Mountain Area Transmission Study, the so called RMATS, here is just an example of some of the scenarios they are looking at. There is a huge coal resource as well as wind resource in the Northern Rockies: Wyoming, Montana, Idaho area. Again, not surprisingly they have scenarios where they are looking to export power into California markets.

Here is one that California has actually been a leader on, the STEP Project. One of their near term actions is to get another Dever-Palo Verde line built. There is great progress on regional planning. Unfortunately, the focus of this is how to bring new gas combined cycle into the state. I suppose that is a good thing to think about, but hopefully we can get their thinking to include some renewable energy issues as well.

There is also something called the Steam Steering Group Western Interconnect. This is an effort to get all of these individual regional plans to be coordinating the best we can. Again, CA ISO is very active in leadership of SGWI efforts. Nothing much on this map other than

again to show that people are drawing lines on maps, and many of these lines lead into California.

Just some other concepts that have been on the drawing board. There has been a lot of issue in the press over the last few weeks on the so called frontier line that can bring large amounts of wind and coal perhaps into the state from the Rocky Mountains.

Another concept that has been thrown out is the notion of building very large wind development in Western British Columbia and in an undersea DC cable bringing it in to San Francisco. Again, there are lots of people trying to think of ways to bring renewable energy into this state. I think we just need to drive it more from a California perspective the best we can.

Again, here is another SSGWI look at the wind resource. This is a dated map, this is probably obsolete by now, but just for illustrative purposes, the SSGWI people did try to inventory the wind resource throughout the west and consider how it could be moved around from where it is produced to where the load centers are.

Here is a map that Elaine showed earlier of the geothermal resource. Elaine's focus was on the California results, this is results from the GeothermEx out of the Tehachapi PIER program activity. Just to focus here, we also look quite closely at the resource in the Nevada which is sizeable. There is a sizeable geothermal resource in the Dixie corridor as well as in the area north and east of Reno.

Again, George discussed the solar resource earlier this morning. It is quite vast within Southern California for concentrating solar power and throughout the whole state with regards to defuse radiation. There is also very large pockets of resources throughout Southern Nevada and Western Arizona as well.

Again, what we tried to do is take some of this knowledge that we have on the renewable resource and, again, work for illustrative purposes begin to do some representative analysis of what it might take to move this power into the state.

As you will see from a discussion that Ron Davis is going to give as part of this program this afternoon, it is not just a matter of getting

it into this state. Once you get it into this state, you've got to get it from the borders of the state into load centers, and that in itself is no small challenge.

What we tried to do is identify specific resource areas that were plausibly developable. We focused on large chunks of resource. There is always going to be the small project opportunities here and there that the private sector is able to make happen in conjunction with their utility customers. For planning purposes, we tried to look at big chunks of power and to bring them in for the most part through the transmission corridors that were already in place.

Here is what we came up with, with some (indiscernible), first look at the State of Nevada, there is a very large geothermal resource in the Dixie Valley, some of which has already been developed to serve earlier California markets and of recent, Vulcan and Edison have been working together to further develop that resource.

There is also a very large geothermal resource as I mentioned north and east of Reno. On the wind side, we have been working cooperatively with the State of Nevada on some of

the wind assessment they have been doing, and there is some good wind resource in Northern Nevada, and then looking at that resource area identify it, the sort of California/Nevada/Oregon border in northeastern California in Lassen and Lodi County as well as in northwestern Nevada and southeastern Oregon, we believe there is a very large high quality wind resource, and then up at the Washington/Oregon border, there is a vast wind resource upwards of 5,000 MWs.

Just for some complete lists, we represented some solar resource in southern Nevada and western Arizona as well.

Some other ideas that we kicked around, and these are very viable resources, but again, we just wanted to do a limited representation of some plausible scenarios, but again, there is such a vast solar resource within California. It may not be that useful to evaluate importing very much of it.

However there is a very large wind resource in northern New Mexico that could be exploited, and then as I showed on the slides earlier, a very vast, very high quality wind resource in Wyoming and Montana. Obviously, there

the challenge is that the vast transmission distance is a potential for a need to develop new transmission corridors.

With that, that sort of just introduced the rest of the speakers now that will speak to several of the specific scenarios that could be brought forth again. I just want to emphasize that these have not vetted to being the most, the best, or the only by any means, but we did find them to be good representations.

So with that, I believe the next speaker is Dennis Woodford to give a quick overview of some of the technical options -- oh no, Ryan Wiser is going to. I'm sorry, Ryan is going to give an overview of the wind resource throughout the west looking at things like product profiles as it relates to capacity value and other things that eventually become important as you consider the issues in terms of integrating wind with the California grid and the existing transmission network. Ryan.

MR. WISER: Good afternoon, it is a pleasure to be here. In my fifteen minutes, I am going to be talking about what really is a pretty modest project that I and others worked on for the

CEC a month or two ago, a project that is the title of this slide suggests looked at the temporal or time bearing production profiles of wind power projects or possible wind power projects, not only here in California, but also in other parts of the west that might be importable into the State of California.

The project goals here were pretty darn simple. First we wanted to assess the importance of temporal variations of wind output in determining the value of wind power, again, at different resource sites, not only in California but the rest of the west.

Secondly and maybe more importantly from the perspective of this workshop, we wanted to address the question of whether wind resource site outside of California might have a better or a worse match to California's electricity load and prices than might wind resources located within the state.

Ultimately, we also wanted to identify any data sources that we could find that might be helpful to the CEC and to the CEC's consultants in future transmission modeling work and other modeling work that is conducted here.

An important caveat here is that we are clearly only looking at one aspect of the value equation. We are only looking at the temporal element of wind production profiles, clearly a consideration of transmission expansion needs, overall resource quality, and other issues would have to come into play in assessing whether in-state or out of state resources make the most sense. We are focused on only one element of that equation.

To meet the goals that I've just identified, our scope of work involves two separate and somewhat distinct activities. First we wanted to compile and summarize as much data as we could find, at least in the public domain on the temporal wind speed and production patterns of potential wind projects in California and throughout the West.

That involved collecting data not only from actual wind power projects but also project developer projections from anemometers, wind speed measurements, and from true wind models, wind speed estimates as well.

Secondly, building off of some draft work that I and others are conducting at Berkeley

Lab, we wanted to analyze the correlation between those production profiles and California electricity load and California's wholesale electricity prices.

Let me just touch on the top level findings from the data compilation aspect of this work, and I will turn after discussing those findings in a bit more detail, to the summary of the Berkeley Lab findings.

Generally we found that California's wind sites often have peak production as one might expect in the April to July time frame. That makes California's wind sites a relatively good match with California's electricity load and prices at least on a monthly time scale.

That said, if you move to the diurnal profile and look at projected wind output during the day, especially in the peak months during the late spring and early summer, you find that the diurnal profile is somewhat less favorable with peaks that generally occur around midnight and troughs that occur midday, 11:00 a.m./12 noon in that range.

Look at sites outside of California and the rest of the West, you typically find sites

that either have a winter peaking resource, have diurnal or have monthly profiles that are relatively flat, but still have some tendency for a fall, winter, spring peak, that is there are some troughs in output or lows in output during the summer months.

That said, you also find diurnal profiles outside of California that are typically far less pronounced. So, rather than having these significant swings between maximum production in the late evening hours and low production during the midday hours, you have diurnal profiles that are typically far more uniform throughout the day.

Ultimately, combining both of those factors, the monthly profiles and the diurnal profiles, we are led to conclude that there don't appear to be any dramatically better wind resource out there from the perspective of temporal profiles to those that we see in California.

PRESIDING MEMBER GEESMAN: Ryan, what constituted a site?

MR. WISER: I will describe that in a moment.

PRESIDING MEMBER GEESMAN: Okay.

MR. WISER: We define it differently in

different places. I mentioned a moment ago that we collected wind production profile data from a number of different sources. Thankfully for all of you, I will not be going through all of that data today. The data quantity is vast in and of itself.

What I will be focusing on is the production data we were able to obtain from operating wind projects throughout the West. Ultimately, we were able to collect monthly production data from virtually every operating recently constructed wind power project in the western United States.

We were not able to collect data on an hourly basis, that is typically confidentially, but publicly available sources for monthly production are publicly available, and I will be standing through some of those data in a second.

In most of these data, again, do support the conclusions I reached earlier which is the California wind profile is typically a spring/summer peaking resource with significant diurnal profiles. The rest of the West has diurnal and monthly profiles that are substantially different typically than those in

California.

For example, this slide shows monthly production expressed here as a capacity factor from eight somewhat recently constructed wind projects in California. These include projects in Solano, San Gorgonio, and Tehachapi wind resource areas.

You can very clearly see here peaks in the April to July time frame in terms of monthly production.

Turning from monthly production, a specific wind resource project for particular projects to aggregate production from our three major wind resources passes: Altamont, Tehachapi, and San Gorgonio, again, you can see the same basic picture here. Wind production peaks in the April to July time frame.

On a diurnal basis, and again, still focusing on California's three major wind resource areas, if you just focus on the top three lines there, those are the diurnal profiles for the aggregate production at Altamont, Tehachapi, and San Gorgonio in the month of June. It is actually June 2002. You can see that the monthly profiles are relatively consistent in aggregate among these

sites. Again, as I mentioned early, you have troughs that occur 11:00 a.m./12 noon and peak production in the late evening/early morning hours.

Moving outside of California, first to Oregon and Washington. Here you can see quite a lot of variation in the monthly profile from one site to the next. You can see at least one or two of these sites including the Klondike Wind Project, these are operating wind projects.

At the Klondike Project has a monthly profile that is pretty similar to those that I just showed for California, that is peaks in the late spring/early summer. Many of the other projects either have more uniform monthly profiles from one month to the next or alternatively see winter peaking resources depending on the specific site.

Wyoming very clearly a winter peaking resource with significant troughs during the summer months. Both Colorado which is shown here and New Mexico shown here, in both instances you see somewhat more uniform levels of monthly production, but with some tendency for a lull during the summer months.

That was a lot of data. For those in the back who didn't see it, I apologize. Ultimately, that really is just data. What we really want to know is how those production profiles correlate with electrical loads in California and wholesale market prices in California. That is the data that will ultimately help inform the question about how valuable wind power may be to the State of California on a going forward basis.

That is really the purpose of a almost completed report that I and others at Berkeley Lab have been working on for far too long at this point. I think I've said just about completed for several months now, but I believe it is getting pretty darn close. I will be summarizing some of the key results from that study in a moment.

Before I do that, though, I want to summarize some of the key points of our methodology because it certainly forms the results that I will present in a moment.

First out of necessity, we principally did not rely on actual production data from operating wind projects. As I mentioned a few moments ago, we were able to obtain monthly

production data from operating wind projects, but not very much hourly production data from wind projects, especially outside of California.

As a result, we principally relied upon anemometer wind speed measurements and true wind modeled wind speed numbers for diurnal and monthly profiles.

Ultimately we correlated those monthly profiles and diurnal wind production profiles with several different wind value metrics including historical electricity load in California. We specifically looked at expected wind production during the top 10 percent of historic peak load hours in the State of California taking load as an average between the 2002 and 2003 value.

We also correlated these wind production patterns with wholesale market prices, both historic market prices based on some pretty dated power exchange, CAL PX prices as well as a forecast of wholesale market prices generated by the CEC in the year 2003.

Third and an important note here is that there is a key limitation. The limitation is there are two data stats, that is the anemometer wind speed measurements and the true end modeled

wind speeds ultimately disagree to some degree on the wind speed pattern, especially during the summer afternoon time frame here in California. You will see some of that disagreement in a couple of slides.

Also, it is useful to note that at least for the data that I am going to be presenting here, we have focused exclusively on areas where we were able to obtain anemometer data. So, that specifically includes the resource areas identified in this slide which of course includes all of the major existing wind resource passes and sites in California, but does not necessarily exhaustively cover all perspective or future sites.

The same thing with the Northwest, lots of data for Oregon and Washington, significantly less data for some of the other areas, but generally speaking covering most of the perspective wind resource areas in these states, but certainly not all of the perspective wind resource areas.

What did we find? Again, let me start with the top level findings, and then I will dig down and show you a couple of the more specific

results. First focusing on wind production during the top ten percent of California's historic peak load hours. We actually find that there are quite a lot of variation in the wind production during those top ten percent of load hours, depending on the specific wind resource area or site that you are looking at.

Specifically, those sites with the most favorable temporal patterns, those that are most well correlated with historic California load generally capacity factors in the top ten percent of load hours. It can be as much as 50 percent higher than their annual average capacity factor, except the annual average capacity factor is 30 percent, the wind projects capacity factor on the top 10 percent of load hours may be 45 percent.

That said, the worst timed sites have exactly the opposite effect, that is, their capacity factor may be up to 50 percent below their annual average during those top 10 percent of peak load hours.

When we correlate the wind production data with wholesale market prices as opposed to electrical load, we find that variations among sites become far less significant, in fact, we

find that the best timed sites may have a wholesale market value that is as much as about five percent higher than a flat block of base load power. The sites with the worst timing with wholesale market prices may have a wholesale market value that is as low as ten percent below that of flat block of power. So, it is not a huge amount of variation on that particular metric.

Third, as I noted earlier, we did find some inconsistencies in our two major data sets. Ultimately, though, despite those inconsistencies, we are led to conclude that there is little evidence that there is some mystical wind resource area in the Northwest at least that has a dramatically better temporal profile to California's wind resource areas.

The next two slides show some of these results graphically, this first one focusing on wind power production in California is in the top ten percent of California's historic peak load hours. We can see here that the anemometer data and the TrueWind data actually agree pretty well for the Northwest.

The best wind sites, the ones with the most correlated production with historic

California load have production during the top ten percent of peak load hours, which is much as about 25 percent higher than their annual average. The worst time sites have peak load hour production that is 50 percent below the annual average for that particular site.

For California on the other hand, big discrepancies between the anemometer and TrueWind data. Ultimately, however, we did have actual wind production data from three specific wind resource areas in California and the aggregate production from Altamont, Tehachapi, and San Gorgonio, those data are provided over here, and you can see depending on the site, you have production during the top ten percent of peak load hours that can be as much as 15 to 20 percent higher than the annual average and as little as about 15 percent below the annual average.

Turning to the correlation with wholesale market prices, those data are provided here. The pink represents forecast prices into the future. The blue or purple or whatever that color is represents historic prices. Again, you can see some level of agreement among the Northwestern sites shown here and a more

substantial amount of disagreement for the California sites. You can also see that for the three general wind resource areas for which we have actual production data in California, again, Altamont Tehachapi, and San Gorgonio, there is a somewhat negative correlation between the production from those resource areas and both historic and forecast wholesale market prices since the value of those sites may be anywhere from five to ten percent at most less than that of a flat block of power.

What that means is that if you expect wholesale market prices to be let's say six cents per KWh into the future, these wind resource sites may have a wholesale market value that is as much as .6 cents per KWh hour or 10 percent below that 6 cent per KWh level.

To conclude, we find the temporal variations and wind patterns indeed can have an affect on the value of wind generated electricity. That said, I think it deserve note that even the best and worst time sites may have a wholesale market value that only ranges from about 5 percent above to 10 percent below a flat block of power so perhaps one should not overstate the importance of

the temporal variations, at least based on that particular metric.

Secondly, we find that California's existing wind sites generally do have relatively favorable monthly production profiles in the late spring/early summer peaks, but at the same time, the diurnal profiles are not nearly as favorable.

Finally, again, we have no evidence that there is some amazing wind resource located outside of California that would be a far better match to California's load or prices than the wind resource located within the state. I believe that's it for me.

MR. SIMONS: We are going to have Dennis Woodford from Electranix come up and talk about the transmission system and the situation in the WECC. I did want to mention that after Dennis talks, Jon Wellinghoff from the Nevada Clean Energy Coalition is going to be talking to us which is a change from what you had in the agenda before.

MR. WOODFORD: Thanks, George. Commissioners and ladies and gentlemen, here we have here the WECC presently approved maximum transfer capacities on the existing transmission

into and out of California.

The ones with the double stars on them that is very lucky if you can reach that level. Usually it is less than that. The existing transmission interconnections in general have their capacity fully contracted, so to bring substantial renewable energy into the state requires either the new transmission contracts need to be developed to accommodate that, or the transmission system needs to be upgraded to increase transmission capacity.

If there is wind, particularly up in the north, say in Oregon or Columbia River, that could be integrated with the hydro system, the Columbia River hydro system, for example, and you could share the transmission so that when the wind is blowing it back off the water, when the wind is not blowing, you use the water that you backed off. That really wouldn't require much more in the way of transmission capacity.

These are the transmission lines as they look geographically. It should be appreciated that we can upgrade or construction transmission across the California border, but that is only 1/3 of the point which has been pointed out by Ray,

and again, it will be pointed out and emphasized by Ron, that you've got 1/3 is also what you do at the load. Hey you get that power into the load which means you might have to upgrade your transmission to the load.

The other third, of course, is collecting it. The transmission, I should say the resources such as the geothermal resources in Northern Nevada are spread over quite a wide area, which means you've got to have a pretty good transmission system to collect all of that in, and you are not going to get that built over night.

To look at what can be done with increasing interconnection into California, increasing the capacity in the near term, say by 2010, and we are largely talking about upgrading existing transmission interconnections.

This is based on the assumption that it would not be possible to permit major transmission in the next five years.

Let me make a general statement. All the exiting interconnections into California can be upgraded for increased capacity, but at some cost, which may not be economical.

Let's consider near term upgrading.

These are just examples and not inclusive. There are many things that we can do, and we are just presenting some examples here. In the short term, we can interconnect the existing transmission if there is capacity available. We can add capacity to existing transmission. We can reconductor, that allows us to increase the current. We can re-insulate which may allow us to increase the voltage. We can covert to dc transmission which allows us to get substantial increase in power. We can add equipment to reduce some of the system constraints that we may generate. This can be done because you really don't need any new right-of-way, so permitting should be faster.

There is a short term example where if we had some development up in the NE part of the state, there is 345 KV line that goes from Sierra Pacific Power up towards the northern part of the state. You can tap onto that and probably with a little bit of luck circulate power into Northern California, subject to the system constraints that are there and particularly if you can integrate that wind generation with hydro systems in the North. You may be able to do that without imposing too much on the existing capacity.

There is another example. It is kind of an interesting example. Coming into this area from the Reno area is two 115 KV lines through PG & E territory, and you could upgrade one of those lines to dc transmission as an end objective, but let's look at some of the options we could also do.

We could re-conductor and here in California we make a composite core conductor, and if we re-conduct it with a conductor of the same weight that exists, you can get about twice the current down it than the existing conductors have, so you get 100 percent increase in capacity.

Option 2 is you could re-insulate, and I've said to 150 KV DC because it might be a step to go to DC as a second stage. First go to a higher AC voltage, say to 150 KV. This probably would give you 30 percent increase in capacity while you are still running with AC.

If you converted one of those circuits to DC because you still need the other circuit to service the loads between here and Reno, you get about a 300 percent increase capacity. These above capacity increases are subject to limits by system constraints, and they may not be as

optimistic as are presented here.

To give you another example of where you could really produce power, again, this would be conversion from AC to DC, if we took the Westwing - Mead - Adelanto 500 kV line, you could convert that to DC all the way from Westwing in Arizona over to Adelanto. Providing all of the infrastructure was in place to do that, you could get 100 percent increase in capacity, which would increase the power transfer about another 1,200 MW.

Just looking at the cost of the interconnection and not considering the sending end collector system or the receiving end distribution system, the costs that it would probably take if we did it today just in capital costs, if we wanted to tap the 345kV line from Reno up towards Northern California with a wind farm up there, we could probably put the 250 MW on quite cheap, just a substation and a little bit of line, and it could easily be done.

We could upgrade if we are looking at upgrading the Westwing - Mead - Adelanto 500kV line, we could probably get double capacity say 1,200 MW extra put on that. There's a fair bit of

cost involved, and it costs as you can see in dollars per KW, 214 MW, $8 per KW.

If we took our little lines across through the Donner Pass and converted one of those to DC, we can get a substantial increase in capacity to do that providing you've re-conducted and re-insulated, but with a substantial capital cost.

Now why would you ever expend that much money to do that. The only reason you would spend that money is you have no other option and you had your back against the wall, but it could be done. At the moment, those lines are rated at 160 MW on a good day.

When we talk about the longer term, now I've got to deal with a substantial amount of planning and study. We have right-of-way to acquire, permitting, we've got financing, and we need to have an adequate transmission infrastructure at both the sending end and receiving end to reduce the system constraints that you may impose by bringing more power into the state.

The one that we have studied quite a lot in our work with Hetch Hetch and the CEC has been

tapping the Pacific Intertie, the HVDC Intertie. This is just a simple diagram of how this is done. The technology is not unique, it is done in the Hydro Quebec to the New England DC line, there is a three terminal line there.

Here we are tapping directly onto the line somewhere around Northern Nevada from our renewable resources. The tap itself could be put in itself pretty straightforwardly and pretty easily. It costs you money, but now you've got to collect it. If it was a simple generating station like (indiscernible), then there is no significant transmission involved.

If you've got to come from hundreds of miles from way into Nevada, pick up geothermal sites, then that becomes significant. Now you have an interesting question because do you want to superimpose that transmission system you are constructing over and separate from Sierra Pacific Power System. That in itself might raise some interesting debate.

Here is how you might do that, it is a simple tap somewhere there north there of Reno or it could be south of Reno.

What would be more desirable from a

system perspective is to get 500 kV AC transmission through the Sierra Nevadas. Here are three options. They are not the only three options, but they are three options. If you could integrate that with the tapping of the Pacific Intertie, now you have something substantial. You have a firm anchor point for the tap so that you don't disrupt the power system of the Sierra Pacific Power. You could link into the Sierra Pacific Power, they could trade off and on into and out of the system, and that would add another path down from the Pacific Northwest.

A nice little scheme if you had Northeast California wind, if you could tap on to the top end of the PG & E transmission system with a 230 line perhaps through the Fredonyer Pass, and you could get a couple hundred MWs, and our study show that could be done. Now this, again, is just theoretical, it hasn't been exhaustively studied, but it is conceptual at this stage.

Another obvious one is to take that 345kV line that ends up near Alturas and move it over to Southern Oregon to Captain Jack, and that would probably help you a little bit in terms of exporting out of Northeast Nevada.

Just looking at some of these limited applications here and selected group, tapping the PDCI with no connection to the existing transmission AC system of Sierra Pacific Power, it is fairly reasonable, $157 a KW. It is about 1,500 MW tap there. If you could reinforce that with a Trans Sierra 500 kV ac line, you get much more than the 1,500 MW. How much more I don't know, but it would cost you more because you would have to build the Trans-Sierra transmission line.

For a little 230 line that you could bring down through the Fredonyer Pass, it still costs a bit of money. So, whatever is selected for these, we don't know what would be selected, and the developers and the utilities would have to find what is the most cost effective, but there are many options. This is just showing you that there are some things that can be done.

As you do that, as you add transmission capacity, we may create congestion elsewhere, and as we've said, the renewable energy collector system may not be insignificant, particularly if it is spread over a wide range.

If we wanted to bring more power down from the north, the Pacific Northwest, we could

add a new 500 kV ac transmission line to bring four of the Pacific Intertie, that would another 1,200 plus MW capacity down from the north.

If we wanted to really develop the capacity down from the north, we could take one of the 500 kV circuits that comes all the way down say from the Columbia River down into the Sacramento Bay Area, and if we converted that to dc transmission, we could get or increase the capacity on that one circuit from about 1,200 MW up to 3,500 MW. Now that is a substantial effort to do that, but it could be done. We might have to think beyond more than the system constraints that we now use.

For one example, in order to minimize the effect of the system constraints that now limit us, perhaps we could segment Northern California at the California/Oregon border, the Donner Pass, perhaps at Path 15 with back to back dc transmission or dc transmission, and with those system constraints changed now, you might be able to significantly increase your import capability into the State of Northern California. I should say into Northern California.

I think that is it. Thank you.

MR. SIMONS: I did mention that Jon Wellinghoff from Nevada Clean Energy Coalition is going to come and talk about options for exporting Nevada renewables into California.

MR. WELLINGHOFF: If I could speak from here. Commissioner Geesman, I don't have specific slides, but I do appreciate you accommodating me on the agenda and allowing me an opportunity to give this presentation, a very short one actually.

The Nevada Clean Air Coalition was formed in Nevada about three weeks ago, however, I have been working in Nevada, I am an attorney with the Law Firm of Beckley Singleton, and I've been working with a number of renewable developers and public interest groups there for a number of years. I in fact was the author of the Nevada Renewable Portfolio Standard legislation and worked in getting that through the legislation, and I've done some work on the California legislation. I most recently was involved in the Colorado legislation, the Renewable Portfolio Standard there, so I've been an energy attorney for thirty years and have been involved in the energy arena. Most recently I have been an advocate of renewables and been working with a

number of entities to advocate renewables.

We are very appreciative of the funding that the Commission has provided to the Hetch Hetch study here and the work that Ray Dracker and Dennis Woodford and his people have done to study these options and alternatives in Nevada.

We believe this is a very dynamic process. You have talked today here this morning earlier about the resource assessment. You talked also about the technological feasibility. I understand you are going to have another session on the economics, but this is all a dynamic process.

Our coalition is composed of about eighteen groups, diverse groups including entities such as CERT here from California is a member of our coalition, the Sierra Club, NRDC, Western Resource Advocates, a number of local groups in Nevada, and others.

Our primary concern is to see that the renewables that have been talked about here this morning and later on this afternoon that are available in Nevada that could be exported to California, that option continues to become available to California.

Our concern is that the PDCI, there is a lot of potential competition for that line. For example Sempra Generation, a subsidiary of Sempra Energy in San Diego, is now proposing that a 1,450 MW coal-fire power plant be constructed some 10 1/2 miles northeast of Gerlach, which is approximately 100 miles north of Reno, and that they tap on the PDCI and use that line to transport their coal generation into California.

We believe that is not the highest and best use of that line. We believe the highest and best use is in fact the development of the geothermal and wind energy resources that you've all be discussing here today and utilization of those resources, both for Nevada and California.

We certainly believe that there is sufficient resources there to provide for California as well as to meet Nevada's needs under RPS. In fact, we believe that if we were to tap the PDCI and develop those resources we have there for export into California, that it would also drive down the price of those resources for Nevada as well and make some of them available there too.

I would just like to express our interest in your work here, hope that you do look

at these issues with respect to other competing resources such as coal plants that are being proposed for this line and in that regard, hopefully you can put together some workshops to look at how these competing issues can be addressed. Thank you very much.

MR. SIMONS: We are going to end the presentations with Ron Davis from DPC talking about bringing renewables into California.

MR. DAVIS: Good afternoon. You have heard a lot of talk this afternoon about bringing all of this transmission and all of this power into California, but one of the things is what happens when it gets to California. Where does it go, is it going to get delivered to load? That is what I am going to talk a little bit this afternoon is, yes, we can build a lot of this transmission, and we can build a lot of the new 500 kV lines, but what happens once we build those and what happens to the system once we get it home, and do we need to begin looking at our infrastructure, our 230 and 115 lines to be able to get it from when we bring the 500 in to get it to the load?

I am going to look at two issues. One

is the near term. One of the things that I want to look at is how is the PDCI and the COI line been used in the past, and can it be used in short term out to about 2010 to bring home some power. What are the issues and what are some of the problems.

The other one is I want to talk about some of the long term intertie requirements and some of the problems that occur as we look at trying to bring a lot of these MW from out of state and trying to bring them home.

A couple of questions that we looked at is how do transmission owners currently using the dc line and the COI in the past and what is the potential availability for base load and intermittent resources to come down on those lines in the near term, and what work must be completed to determine the availability?

If I was to look at 1996 to 1999 for the DC line, and we looked at the rating in line as 2,900, and if we look at just couple, July and August, for these periods, we see that the maximum usage of the lines is very high. So, during the peak load periods in the summer, they are used in this line up to its maximum.

However, if we look at the average hourly loading during the heavy load periods, we also see that is very high in the 1996 to 1999 period, they are in the 80 to 90 percent time period.

Also except for a few months, the rating of the line during those heavy load periods on peak has been pretty high. You see in August of 1998 drop down to 1780 was the average on-peak availability of the line, but for the most part it was pretty high.

If we were to look at 2000-2004, you see that on-peak the utilities tend to still schedule pretty high on the line. Although there has been de-ratings on the line during on-peak periods during this time, and I'll get into that in a minute, but I think the average on-peak usage is the one that is of interest.

The average on-peak usage of the line has really dropped from the 1996-1999 period, and so the average usage on the line has been down.

The maximum peak usage of the DC line in the 1990's was 98 percent, the average in the 2000's was 90 percent. The average hourly heavy load period has been around 90 percent in the

1990's and 79 percent in the 2000.

The average usage has changed, 81 percent in the 1990's and 50 percent in the 2000's. There are several reasons for this, and I think one of the first ones I didn't put on here was there was a lot of work being done on the DC line I believe in the last three years or four years. So, there was a lot of upgrades and a lot of advancements made, so that has tended to pull that down.

Our load growth has been down, so, therefore, we are not buying as much power. The Northwest has had some dry hydro conditions. The Northwest customers have been using more hydro, and there is more and more and less excess energy to be able to import into California.

If I was to look at some of the actual loading on the line for these time periods, you see in August of '97, the usage was pretty high towards the rating of the line.

In 2001, you will notice that the rating usage has dropped considerably, but also there has been a lot of things happening on the curtailment of the times, and I think this was due to the loading and the work being done on the line.

You will also notice a period where they had been starting to do some paybacks off-peak. So, we have been scheduling on-peak and doing some return energy off-peak.

In August of 2004, you can see what happens to the curtailment, there has been a lot of work done on the lines, so, this one is really a difficult one to kind of use to see what's happening, and this came from BPA's website on the rating and the usage of the line.

If I was to look at the COI for the trading of 4,800 in the same time period of 1990's, we see that the usage has been up very high on-peak, it has been in the 90's, upper 90 percent. Also during the average heavy load hours for the on-peak period, it has been pretty high also.

In the 2000's, you see that the maximum usage has dropped a little bit, not as high in the 90's but in the upper 80's, and the usage off-peak, the average hourly loading on the peak hour periods has also dropped a little bit.

If we look at the peak usage during the peak hour, it was 89 percent in the 1990's and 87 percent in the 2000's. The heavy load hourly

rating has remained pretty constant, 85 percent in the 1990's and 83 percent in the 2000.

Here again, I think we have the same thing as dealing with what's available up in the Northwest currently coming down and how much energy is really available.

What is interesting is if we look at August of 1997, on-peak was pretty well matching, we were full loading it during the on-peak periods and taking a lot of power consistently off-peak, so we were loading it up pretty good.

If we were to look at August 2001, the peak usage has varied a little bit, we are not using as much as we were. If we look at August 2004, you see some variations, so the utilities I think are tending to do more purchase of on-peak shaped power from the Northwest.

Coi curtailments will impact the availability to some extent. I think wind and other intermittent resources could deliver power during these non-peak periods, so I think a lot of this stuff talking about integrating hydro with wind fits very good with this schedule to be able to flatten out the usage of the lines. I know there is a lot of utilities that are currently

negotiating contracts in the Northwest to do exactly that.

One of the things to try and bring in some geothermal on this would be considering the utilities are trying to buy hydro on-peak would be whether or not the geothermal units would be curtailed during the on-peak period to make room for this.

Another would be could you do something similar to the hydro wind where you could do something with the geothermal on the hydro to kind of flatten out the hydro a little bit more instead of having it being shaped power product, but have it more evenly over the on-peak periods and allow a little more geothermal to come in.

Some of the other problems is with PDCI and the Coi lines are the nomograms impact the ratings a lot as it comes down. I have heard a lot of talk here today about the tapping into the DC line. The nomograms are something we are going to have to be very careful of, and the flows in the lines and the COI and PDCI. As you load up either the COI or PDCI or both, there is going to be an impact on how much can really flow and what the nomograms look like.

In conclusion, I think on the short term, there is I think availability that we can do on the COI and the PDCI to bring some power home. I think there has to be some additional studies done to look at whether or not how much we can bring down, what kind of product we can bring down. I think there is potentially to do some things on short term.

I want to talk a little bit about the long term transmission of bringing power home. What I want to assume here for after 2010, is that we have loaded up fully the COI lines and the DC line as much as we could. So, we have maximum imports coming over the COI and the DC line. It is really looking at a maximum stress case.

What I am saying is if we fully load up the lines and we currently our existing system, what happens to the rest of the system, or what happens to our infrastructure, and that is what I want to talk about this afternoon in more detail.

So, if we assume it is 2010 summer peak case, and we assume that the interties are maximumally loaded, we want to look at the available transmission capacity, an amount that can be transferred into the state and what happens

to our infrastructure system as we begin to try bring more power in.

We modeled three out-of-state renewable resource groups, and we modeled proposed high-voltage transmission upgrades. We did not look at some of the 230 conversions, we stayed more with the DC line and the COI line, we looked at the Palo Verde Devers, so we tried to look at a group of resources coming in, but we looked at the high side voltage.

We wanted to calculate the peak hour available transfer capability from out-of-state resources into California and what happens to our system. We wanted to determine how much power could be imported in before we began to have problems.

Using the map that Ray had shown earlier, we broke it into three out-of-state groups. We had the Northwest Group, the Reno Source, and the Southern Source. I think Ray had shown that map before.

Proposed transmission upgrades we looked at. Option 1 was a California intertie, another line, a fourth line coming down on the Coi.

A Trans-Sierra high-voltage line coming

through Susanville. We also looked at another high-voltage Trans-Sierra line that modeled after what Ray and Dennis had talked about coming over from Reno area. The results were pretty similar to Susanville, so I am not going to go into it.

Then we talked about the DC line, what if we tried to bring more power in over the DC or tried to do some upgrades to the DC. The other one was the Palo Verde-Devers line.

Our methodology that we used on looking at available transfer capability was to look at a peak load case. We ramped up the out-of-state renewable generators, and if we needed to, we ramped down in-state generators except for nuclear base load, the RMR units, and renewables. So, we left the in-state renewables at max.

We considered all single transmission outages above 100 KV, and we are looking at n-1, and we determined which transmission elements will become overloaded by importing renewables. So, what we wanted to look at was how much more can we import, which transmission lines cause limitations,and which outages cause limitations.

If I was just to look at this and look at one of the examples of an import limiter, we

see that as we start to bring down or import more out-of-state resources without any transmission upgrades, the Coi lines become the limiting factors.

As you can see by the yellow areas, it says as we try to bring more power in, the COI becomes the limiting factor. You see the dark red area over here, it is kind of hard to see, that is in the Bay Area, that is as we start to bring up, we start to have transmission problems and congestion areas in trying to get power coming down from the COI to get it to the load centers.

If we were to add a fourth transmission line on the COI, and we look at now what happens, you see that there are no more yellow lines because we added a fourth line, but the red area has increased. What that is indicating is that our infrastructure is beginning to have problems and that we are trying to import more and more power, but we can't get it from where the 500 terminates down to where our load centers are.

On this one, I just wanted to show that if I had no transmission upgrades, but I was trying to maximize my imports into the system, and I was to lose the Miguel 500/230 transformer,

power actually increases on the COI and increases by 3.6 percent. What we are trying to show on here is the system is so tied together that an outage in the southern part of the state will impact those in the northern part of the state.

As we start to look at the system, we need to study all of California and looking at the entire system and the impacts as they will have on the delivery of power from different interconnection points.

If we had that same Miguel transformer out, but we were to build a fourth COI line, you see that the flow actually increases from 3.6 to 3.7 percent coming down on the COI line, but it is more evenly distributed because of that.

Even adding the other line, and here again, I did not try to do any upgrades down into the Miguel substation or try doing improvements that San Diego was trying to propose, I just took the 2010 data set.

Even just by building another COI line, we've still got a relationship of the flows are so intertwined and interconnected that an outage in one part of the state can affect the delivery and the imports in another part.

What I want to talk about on this is what is the limiting factors as we start and add additional transmission lines to import more power. This is explained more in a lot greater detail in the white paper talking about what lines and what causes these contingencies, but what I wanted to go over is as we add another four COI line, and we start and load it up, what happens to the infrastructure, what happens to the system.

We see just adding a fourth line, we begin to overload the system, the 230 system and trying to take that power from Tracy Tesla and try to get it out to load.

As we start to load up the line from zero to 1,350 MW, we see that there are five contingencies occur in the line as we start our run our n-1 that impact the loading and the capability of the system to bring power home.

When we try to go up to 1,458, there are four contingencies that affect the system operation. As you can see, we keep trying to increase from up to 1,700 to get close to the other lines, you can see the number of contingencies increase as we try to load COI line up, which is indicating that our infrastructure,

we've got to spend more time looking at our infrastructure and what are the requirements in order to be able to deliver the power to the load center.

Here again, I think if you look at the white paper, we go into a lot more detail and actually list a lot of the lines and they are associated with these contingencies.

If we were to build a new Trans-Sierra line, you can see what happens when we try to load it up. One of the things with the Trans-Sierra line, it is still going to come over and it is either going to tap into the Round Mountain, Table Mountain, or it is going to come down into Tesla as I think Dennis has talked about, that it is going to come in and tap somewhere around in or around where the COI line is.

You can see that if you try to build a Trans-Sierra line that our outages and our contingencies really increase. If we try to get above about 440 MW, there are 29 contingencies that affect the loading of the line as you try to go above about 440 MW.

If you even try to build a Trans-Sierra line and you try to load it up, our infrastructure

is getting to the point where it can't deliver the power to the load centers, and you are seeing the impact of different outages that are affecting the system.

We next took a look at what happens if we try to bring more power in over the DC line. This was interesting in looking at because if you notice, even though we are saying we are going to do some improvements to the DC line, the COI line is the one that is getting impacted. I think some of the reasons for this is the fact that the nomograms and how the power is flowing, whether or not you disconnect into the DC line, some of the power is still going to go north and come down on the COI. You can see that the contingencies increase and as we load up the line, we see that we have base case violations and we also have a lot of contingencies that affect the operation of the system.

This is also kind of interesting if we do the Palo Verde-Devers 2 line, COI gets affected again. As we start and load things up now, this is without adding a fourth COI line, this is having the three lines in there. As we begin to load up the lines, we also begin to see that we

are overloading some of the COI lines as we do contingency analysis.

Some of the limitations that we did and the time period that we had to do this study in, that is why we looked at A2C just to transfer capability is that we took a snapshot of the summer period and the transmission loading during the peak loads are not necessarily the same as off peak. We may be able to import more power during the off-peak hours.

Another issue is the unit commitment affects import capability. We do not have time to relook at how we would do a re-dispatch of the system and see what we do our units to alter some of these contingency problems. We didn't have sufficient time to go through that.

We didn't do a lot of things and some of the other issues is imports from other control areas as we come in and we look at these and see what impact if we could change some of that to reduce the amount of over loads.

Conclusions that I wanted to come away from is COI is going to be the limiting factor as we look at trying to import power from out-of-state resources. Also as we begin to look at

bringing all of this power from Oregon, Washington, and other states, we must begin to look transmission upgrades inside the state to get from the delivery point home, so we need to begin looking in a lot more detail on the infrastructure of the 230 and 115 system.

If we are going to prepare to build some transmission lines, we've got to also improving our lines to get it from to load.

Here again for this analysis, we looked at 2010 and what would happen. One of the other issues as we began to look out further in time after 2017 and especially where you look at beyond the 20 percent penetration but going up to 33 percent, then we need to look more and more at infrastructure to be able to get the power home.

I think what needs to be happening is we need to conduct more seasonal transmission power flows. I think we need to get into doing more detailed power flows, and I also think that we need to integrate a power simulation model, production cost model into our analysis.

Here again, we just looked at a transmission model given with what we could get done here. We need a model interstate flows with

and without renewable imports to see what happens with the system as we do more of just our internal system, and then we bring in more from out-of-state.

Then we need to evaluate and monitor transmission interconnections from other regions. I think it was brought up this morning about all these different regions that are looking at connecting to California.

One of the things I think that needs to be done is if you look at where they are connecting, the ones that are coming to Northern California are coming to Tracy and Cobb or they are coming to Table Mountain or Round Mountain. That doesn't necessarily help us any because you are tying in to the COI line. As you look at trying to bring more power into those points, you are going to have more power getting the power to the load on those areas which we are already looking at having problems down the road.

I think we need to look at more of what they are doing and maybe even directing them and looking at where we should connect these. If we are going to bring more power in from out-of-state, and we are going to build new transmission

lines, where should they connect to. I am not sure Tracy and Tesla are the right areas that you want to bring it into to. Where should we bring these in, where should we encourage if there is going to be any development, where should these be, where should they connect to, and what are the potential problems that we have to resolve before the lines get built.

I think that is all I have for this presentation.

MR. SIMONS: Ron, actually before you leave, I did want to ask one question. One of the earlier discussions that we had, it appeared to me that by 2010 given the DC COI limitations, that the most we could import into California was around 500 MW by 2010, is that correct?

MR. DAVIS: I think in the integration work that we are working on now for the June presentation, I think we are up to about 1,000 MW. If it is going to be shaped like a wind hydro project and I showed you those potentials that not only the on-peaks not being used, but we are up to about 1,000 MW or 1,200 MW that could be brought in, and we are assuming that some of that will be the geothermal from Nevada and then wind

integrated with the hydro to flatten out and be able to bring more power home.

MR. SIMONS: We are going to go ahead and shift and we do have a panel. Thank you, Ron. We do have a panel for this afternoon also. Again, we had SDG & E -- we had the IOU's and if people from -- if the panelist members can come up and sit around. Again, I don't know if we would like to take a short --

PRESIDING MEMBER GEESMAN: Let's take a break.

MR. SIMONS: Okay, let's take a break, and then just have the panelists come up.

(Off the record.)

MR. SIMONS: We are minus some panel members, but let's get started. Again, this afternoon we were really focused on interstate renewables and most of the questions have to deal with bringing renewables into California and types of transmission and distribution constraints that we face, the intertie constraints.

Again, I will go ahead and start with some of the questions that we had on the agenda. Is there sufficient transmission capacity, either physical or contractual, within the WECC

California area to bring some amount of renewable generation into California by 2010 and 2017 that may have been missed in this analysis? Otherwise are we capturing the full set of transmission possibilities, or have we just missed the mark here?

We will go ahead and start with PG & E.

MR. FILIPPI: Hello, I'm Jim Filippi from PG & E. I think in general, the presentation I saw today was a good start. The amount of renewables that can brought in over the existing transmission will depend on, you know, what are the existing commitments on the lines and then after that, what are the competitiveness of those renewable resources with the other resources that are available to be imported.

So, yeah, I think there is some possibility there that there may be some capacity that the load serving entities can when they are able to get firm transmission rights to bring those resources in, there may be some existing capacity that can be used for that purpose in the short term.

The long term, it will depend on future projects that need to be developed.

Some of the alternatives that I saw today looked -- well, they are concepts that are probably pretty far out of the box. Some areas we've tried before, and were pretty contentious such as Trans-Sierra areas. I will also point out that there is a lot of analysis that needs to be done before a line can actually be developed, things that haven't been touched on like dynamics, stability.

Anyway, I thought it was a good start, the presentations today.

PRESIDING MEMBER GEESMAN: Yeah, I would echo what you said about Trans-Sierra. I mean history would suggest that proposing that is equivalent to proposing another nuclear power plant here in California.

I guess the fundamental question that I would pose is that if California ends up being the market that drives development of these generation projects around the West and recognizing the work that the Energy Commission has had underway with the Western Governor's Association for a couple of years now to develop a RGIS accounting system for renewable energy certificates, wouldn't it be a lot cheaper to see that certificate trading system

brought on line rather than building a lot of 500 KV lines to support shipping the actual electrons to California?

MR. FILIPPI: I'm not an expert on this certificate system, but certainly I will say that the transmission lines are going to have a large cost. The other side of it is if you build those resources and you don't have the transmission, where is the output going to go. So, you know, the regional study groups have done studies, scenario studies, different generation scenarios. For instance, they put a lot of coal in Wyoming or they put wind resources in different places and just look these were just production simulations, they looked to see where the power would go. It naturally grafted towards California because the existing resources are relatively high cost, so it would displace those.

Certainly the main question on exporting renewable resources is it worth the very high cost of the transmission. It is not just an economic cost, there is also an environmental cost.

PRESIDING MEMBER GEESMAN: Yeah. It just seems to me that we do such a poor job of building and permitting our transmission system

inside the state, that state government really needs to get its own house in order on this subject before searches too far outside the state boundaries for additional transmission projects.

MR. FILIPPI: Yes, another thing to consider is that it is hard enough to permit resources and transmission within a state, but going across state lines, having multi-state projects is difficult, and then I think it adds a whole other layer of complexity then to have out-of-state resources and out-of-state transmission that are developed primarily for exporting to California. That is another difficulty that would need to be overcome.

PRESIDING MEMBER GEESMAN: Thank you for your comments.

MR. SIMONS: Jorge.

MR. CHACON: Good afternoon. My name is Jorge Chacon. I represent Southern California Edison. A couple of comments that I came across from these presentations. I think first of all is looking outside the state, and you look at these renewable resource projects trying to get to California, from a transmission planning perspective in Northern California, one can assume

that somehow they are going to manage to find a way to a ISO control point because if that is not the case, then the first question that comes about is if we are having difficulty permitting and financing from a generator perspective side facilities within in California, how are we going to do it outside when I don't believe those other utilities are going to be willing to submit a proposal to FERC and say there are the costs so long as they can get the money back similar to the Edison proposal. That is the first comment.

The second comment is if you do get into an ISO interconnection point and some of the charts indicated that there presumably is some kind of capacity available, I think some of those bar charts or some of those graphs are a little misleading because we have entities that are under ISO control and then entities that are not under ISO control and capacity is shared among all parties. The fact that you are not loading up the facility in and of itself doesn't mean that there is available capacity for the ISO to say schedule over it.

You have a scheduling issue and you know what really flows on it, and I don't know how we

would resolved that, I'll let Jeff comment more on that if he has more comments. He is the ISO.

The last thing that comes to mind here is in trying to bring in more power, presumably you are looking at fulfilling the increase load demands and not so much displacing other resources because we are somewhat in a capacity shortage. So, to do that, you either have to increase the path rating somehow so you can put more power through it, and that in and of itself necessitates a real detailed study process known as the WECC Path Rating for which we identify facilities and then try to achieve a particular path rating.

We are talking about utilizing the existing path ratings to try and inject more power in it, I just don't see how we are going to be fulfilling the resource demands of say Southern California.

I think those are the three topics and maybe I will come back around as I hear other input, but I think those three topics, you know, when you look at bringing power in from out-of-state to California are somewhat nebulous and a little problematic.

PRESIDING MEMBER GEESMAN: The way it

struck me, and I have not seen this presentation before, I thought it gave Southern California a bit of a short shrift. I actually looked at the Palo Verde hub as a more valuable renewable import hub than the study seemed to suggest, and I note the City of Los Angeles in their claim to be a better sponsor for the Devers Palo Verde II line has suggested that would become the renewable super highway for their system.

It would strike me that a fair amount of the renewable resources attributable to the Northern Rocky Mountain states could just easily be brought south to the Palo Verde hub and then in to California through the Devers Palo Verde II project as could come down COI or certainly across a Trans-Sierra line.

MR. CHACON: That is absolutely correct. You know, the project in and of itself is a transmission project whose sole purpose is to bring energy to not any one specific energy, it could be combined cycle, it could be coal, it could be renewable. Its purpose is to bring additional energy from a renewable or an energy rich area, which is the Palo Verde hub, so to quantify it in such a manner that we are proposing

a project for combined cycle is I think it is sort of an inaccurate as it is to bring in more resources.

PRESIDING MEMBER GEESMAN: Thank you.

MR. SIMONS: Jeff?

MR. MILLER: Yes, thank you for inviting me to be on the panel. I am Jeff Miller with the California ISO. I have three points that I would like to make.

The first is that when you start looking at major inter-regional transmission projects, it is very difficult for any entity, the California ISO, any of the utilities, it is very difficult for any of them to be able to develop significant conclusions about major regional transmission projects, even conceptual ones, that would be widely accepted and most people would believe to be true.

When I looked at some of the projects that were proposed and some of the statements that were made, you know, I had some issues there, and I think many others would, and I would caution the Commission from making any conclusions without the benefit of wide stakeholder review of these types of analyses, I think there is a tremendous amount

to be gained there.

There is a lot of institutional memory of not only within California but across the interconnection. Many of these projects have been looked at in the past. There is a lot to be learned from what we've already done in the past. I think that would help guide future studies. I am not sure how you intend to use them, but I would just caution you that you do need a wider stakeholder group when you want to develop these sorts of transmission projects.

My second point is that when you want to look at the utilization of the system, and this gets to Commissioner Geesman's issue with Palo Verde Devers II, I think it is important to look at how the system is used throughout the year and throughout the day before you determine whether or not there is adequate transmission for the renewables you are investigating.

For example, there was some discussion about, well, transmission is all used up because it is coming in from Arizona, it is fully booked, coming in from the Northwest, it is fully booked, there is no transmission. Well, if you look at how it is actually used, you find that the

transmission from Arizona during summer peak into California is not at a very high level. The transmission from the Northwest into California would be at a very high level.

So, why are we building all of that transmission to Arizona? Well, it is mainly for fall and the winter periods. A lot of that energy goes to feed the Pacific Northwest right through California. It is a regional grid, so you have to understand the diversity on the system before you can make a judgement about whether there is adequate transmission.

How do you do that? I think one of the best tools we have now is production cost simulations, and that came up earlier. I think that would be a very valuable exercise before you determine whether or not you need additional transmission.

Then the third point I would like to make is one that renewables don't necessarily need to be the ones on the margin getting the additional new transmission. There is a fair amount of transmission that is out there for contract either through the ISO's transmission rights or with other entities with contracts.

We are increasing the capability of the system from Arizona and Nevada into California by about 30 percent over the next few years, and most of that transmission will be available to whatever resource wishes to use it. The system is not necessarily unavailable for renewables. It is there.

PRESIDING MEMBER GEESMAN: Jeff, when you speak of that broader stakeholder group, you have in mind things like the step planning process?

MR. MILLER: Yes, and its parent organization SSGWI which is right now developing a new production cost simulation. They did some studies a few years ago looking at integration of renewables west wide just to give policy makers like yourselves some insight into what transmission implications might come out of broad development of renewables. I think that is very valuable.

When you start looking at specific projects like these lines that come into California, you could look at one of the sub-regional groups like Southwest Transmission Expansion Planners STEP or NTAC, Northwest

Transmission Assessment Committee, because there is no expert out there that can tell you at all. You've got to get enough people around the table that know the system to really give you good guidance and to develop a water tight plan.

PRESIDING MEMBER GEESMAN: Thank you.

MR. SIMONS: Dan.

MR. ADLER: Good afternoon, I am Dan Adler with strategic planning at the CPUC. Thank you, Commissioners and advisors for having me up here.

I will say and I always do that I am here representing staff. If anything sounds like an opinion, it is mine and not CPUC's. I've been saying that for a couple of years, I am getting away with it, so I will continue on.

I'm pretty optimistic actually sitting and listening to the two sets, the presentations, for a couple of reasons. One particular to the conversation this morning, I do think that generally we have done a pretty good job over the last several years in putting together the RPS program.

I have a lot of my own skin in the game, so maybe I am a little bit biased, but just

thinking about where we've come, we have now all three utilities engaged in the RPS process. Two of them are either have submitted contracts to the inaugural solicitation or about to.

We met our legislative deadlines. We got the first solicitation up and running in eighteen months. We have identified major transmission issues, major cost issues, and we are poised to do it all again this year. The same time that we are evaluating contracts from last year, we are going to out with another RFO this year.

That is the general, maybe a (indiscernible) view, but just to counteract some of the specific complaints that are valid and we heard this morning.

PRESIDING MEMBER GEESMAN: What is your level of confidence that we are on track to hit our 20 percent goal in 2010?

MR. ADLER: That is actually a good point, and I wanted to get to that. The question was raised earlier how we count in the RPS program. If we were taking the 1078 language to the 2017 date, really the generation has to happen in three years after the contract is signed. If

we apply that same logic to the 2010 target, then I think we have a chance. I'm doubtful just from a practical standpoint we could get all the generation on line by 2010. It may be possible. I think you have to think about what that does to the seller's market if you really want to channel all the infrastructure on in such a short time frame.

That counting flexibility is built into the program. I think we can do it if we take advantage of it, but it will take some transmission work.

Particularly to that, I think that this morning's presentation and this afternoon's reveals that there is so much potential in-state that we can focus on in our near to medium term goals, set the stretch goals to 33 percent goals that we are talking about and begin this more robust regional integration process that will get to some of the concerns about how do we marry the trunk line proposal, if that is the vehicle for this state, with all the interfaces of the other ISO's and other transmission planners outside of the state that we are inevitably going to have to face.

Taking advantage of our natural endowments which are tremendous in the 20 percent part of the goal the same time we move forward on the transmission on the larger goals is I think essential.

The trunk line proposal really to me seems that it is the game, it is the proposal that we have right now. My commission has supported it as your Commission. We need to separate --

PRESIDING MEMBER GEESMAN: Do you see that concept been given broader application than the specific filing that Edison made with FERC?

MR. ADLER: The Tehachapi case?

PRESIDING MEMBER GEESMAN: Yeah.

MR. ADLER: I do, and that was one of the main concerns that the CPUC had. The idea is nice, if it is feasible, we would fully support it in broad application. It is a question of how you design what the next project is, who controls the reigns. I personally don't think that the policy should be the utilities put forward a set of proposals and we react, I think we can be more proactive.

If we have a vehicle that says we have cost recovery outlined, if we have reformed to the

abandoned plant rules that everyone is so concerned about reasonably, but that really solves the payment problem. It doesn't really solve the planning problem, we could still be in a position where we are making substantial bets with ratepayer money on infrastructure projects and with real environmental and economic consequences that are never utilized. That is the worst case scenario.

I think in the best case scenario, you are influencing the competitive dynamics of the RPS bidding process, and I think we have to be up front about that. If we plan and build before competition yields its results, we will be to some extent dictating the technologies and individuals more importantly, individual developers who are going to prevail.

That is something we have to be up front about, but I do think to break the curmudgeon that we have been talking about here and at my agency for several years that this is a reasonable first attempt.

The market redesign issues are particular on my mind now. We have been talking to my commission about implementing a loading

order as we have for the energy action plan in the renewables context. What are the mechanisms to do that? Can we utilize the congestion right allocation process to prioritize for particular types of generation. That flies in the face potentially of the market oriented transmission access plans. In the view of the MRTU process, but none the less, it may be one feasible option and something we should keep on the table.

Let me close by talking about a little bit of lessons learned. I understand that your agency is putting together a lessons learned study from the first RPS round. We intend to do that. That is one of the many things we intend to do this year. One thing that we do I think need to look at is San Diego raised the point that we have the initial bid evaluation process that looks at estimated transmission costs to help in the least cost/best planning process.

It is a very important element of it obviously if we are going to get the best resources. In San Diego's case, it diverged from (indiscernible) substantially by the time they got their bids in, so we really don't have a mechanism, at least not in that sense of

accurately guessing transmission costs before real projects are associated. Ideally those projects would go through a more formal ISO process and get those real costs fixed ahead of time. We are confident that those are the real costs that ratepayers will bear.

Moving in that direction as opposed to what in the best case despite all of our hard work adhoc up front assessments is I think going to be key to making the sort of resource selections.

Finally just in the general procurement opportunities universe, there are several decisions that are going to be made in the near term, but to my mind they are more significant than the details about the contracts, the details in the contracts, the market price reference, inputs and escalations factors, etc. So, it has to do with coal coming from the East, liquefying natural gas coming from the West, and renewable energy certificates being developed in California.

All of those three -- I'm not weighing in on the advisability of any of those elements, I'll probably do that off line. Those three are to me going to have a much greater degree of significance for what we are trying to do in this

room right now than the issues about particular resources in particular contract forms.

PRESIDING MEMBER GEESMAN: Thanks, Dan.

MR. SIMONS: Steve.

MR. MUNSON: Steve Munson, Vulcan Power. It seems like every place you push this balloon that is mostly full of water in California, you have a pressure point appearing at COI, and I'm not sure we have looked at what happens if we add more wind in significant amounts in southern parts of the state. Do we push COI also? Does that mean that we've got to fix this grid, that we really ought to be looking at this as a problem that the renewables are just pointing out instead of a problem that renewables are causing?

It seems to me that if there is no place you can bring renewables into this state, we are going to be hurting, both with respect to total output and meeting the RPS as well.

There is something else we seem to lose track of. It is pretty easy to put a pencil around the location areas of knowing a large renewables, but there is no way to just magically produce all those renewables. To say one company suddenly is in an area and controls an area where

there is a 1,000 MW, it would probably take them eight or ten years, maybe twelve years to develop those, even going full speed even if it is a big company. I think one point we need to make again is that you need diversified resource locations and diversified developers or you are simply not going to meet these goals, and transmission is a key constraint.

Comments were made earlier about the COI and in two different cases, the points were made that for the last four or five years through 2000, the Pacific Northwest has experienced dry hydro conditions, and Pacific Northwest customers are continually using more hydro. Does anybody here think that is going away? We've got 90 percent dry years now.

I am from the Northwest, I am watching what is going on, we are having trouble with our own system up there meeting our requirements. The net effect is that it is opening up substantial capacity. In fact, 49 percent less usage for the 2000 according to the earlier study that Davis gave us some numbers on the COI due largely to dry hydro.

Mirrored over at the PDCI, 50 percent

less usage on the PDCI, again, primarily due to low hydro conditions and Pacific Northwest customers using more hydro. I would like to advance that this creates a good opportunity for California to get behind a program to bring substantial renewables down to COI. There are advanced stage renewables up there, geothermal and wind.

With respect to the PDCI tap that has been talked about, I am puzzled. I am puzzled for a couple of reasons. About a month ago, we were fortunate enough to have a geothermal transmission working group meeting here, which I appreciated the opportunity to speak at, and I presented a letter from Mr. Woodford who is here today which indicated that the PDCI could be tapped for $100 million, produce about 500 MW at a total cost of $200 a KW delivered to Los Angeles.

Now I can't understand why we then have the staff telling us that the PDCI tap needs to be 1,500 MW and located in Northern Nevada where Sempra could produce coal instead of a 500 MW tap down on the California border.

We have a 40,000 acre geothermal property, there is 18 geothermal wells that have

been drilled there and passed their test wells. It looks like there is a couple of hundred MW just on our property. It is not proven yet. There is the Dixie Valley line that comes in from Dixie Valley Nevada that has about 200 MW of unused capacity on that line that passes 12 miles from the PDCI on our property. Located immediately adjacent to the PDCI right into California along the same right-of-way. In fact, that tap could actually be put on the PDCI in California.

I can't understand why it is that under the work that is going on in the staff level that the PDCI is called the long-term upgrade. Mr. Woodford just got done telling us that it is an easy thing to do. You don't have to build a new right-of-way, it is not a long-term matter that we have to study over 15 years. We could put a PDCI tap on and bring in lower costs geothermal from Nevada, then a lot of the geothermal that is in the State of California.

It is fairly well known that a substantial amount of the geothermal in Nevada is a low cost resource. I think California should benefit from it. I think that we ought to be looking or giving at least an equal look to 500 MW

of geothermal on the PDCI down near the border or inside California because it is a near term way to allocate partially unused line.

PRESIDING MEMBER GEESMAN: How would you envision paying for the tap?

MR. MUNSON: The tap could be either paid for by the grid of course. The line is currently owned about as we all know about half and half by SCE and LADWP. The tap could be paid for by the grid, the tap could be paid for by a third party investor like the Path 15 upgrade. In fact, parties we're doing business with helped to fund that Path 15 upgrade and are looking for additional business.

It could be funded by the utilities and rate based. I think this is one of those opportunities for California that there ought to be a working group talking about it.

I could tell you from personal experience that DWP hasn't been very forthcoming on renewables. They haven't done much. They are kind of hanging back or worse, but this is a line that is half owned by SCE. SCE has been pretty pro-active on renewables. I think there is an opportunity that might benefit everyone. We

should at least look at that one.

PRESIDING MEMBER GEESMAN: Who would you envision paying for the collector system inside Nevada?

MR. MUNSON: That was one thing that was actually not fully correct. I would look at most of that collector system in Nevada as being paid for the by the developers. In fact, a substantial part of that collector system is already in place. The Pacific DC intertie line, as I said, is immediately adjacent to the Dixie Valley privately owned geothermal line right now, and FERC requires that line be made available to other developers that want to use that line and of course will have to pay for it. So, there is already a line that's gotten some number like 200 MW or more of available capacity that could serve developers.

There is something like a 150,000 maybe 250,000 acres of geothermal along that line that I am aware of, good looking property. Some of them have steam wells, some don't, within 40 or 50 miles of that property in addition to Dixie Valley which is a big property that is already making 55 MW at the far end.

PRESIDING MEMBER GEESMAN: Thank you.

MR. MUNSON: Yes, sir, thank you.

MR. SIMONS: Bob Anderson.

MR. ANDERSON: Good afternoon, I am Bob Anderson. I participate in the former Commissioner Protection Program, which may be useful to you some day. Part of that program is that I am identified with organizations that I formerly belong to. I am listed as CREPC today. I used to belong to CREPC or participate in it. Today I am really speaking for myself.

Also I have another disclaimer. Commissioner Geesman, you asked about RGIS and developing the Westwide Tracking Program first which RGIS is, and then following on that a trading program. I am the Chairman of the Interim RGIS Governing Committee. RGIS itself has not policy positions, it is policy neutral, it is just infrastructure really, so anything I say is not RGIS position or policy, but I agree it is in the interest of California and the region to have a robust westwide tracking and trading system for renewable credits.

I think that would drive down the price, it would benefit developers, it would benefit consumers, and benefit the environment, so I think

that is a good plan.

It is not an either or proposition, credit trading or transmission. I think we need to have some of both. In the transmission world, this is a fascinating and complex world as you can gather from what has been presented here today.

If you go back a few years, there was almost as a result of restructuring and the crisis, there was very little being done in the way of regional or any kind of transmission planning. We almost took a zero-based approach and started all over with defining roles and responsibilities and opportunities and criteria, that is how you decide what to do and when and who owns it and all of these things.

To their credit, lots of entities have leaped into the breach in the last five years. SSGWI and the sub-regional processes and the CA ISO and some of the utilities like Pacific Corp, they have rightly I think seen that it is partially or a lot their responsibility to do something, and so they are doing a lot.

I did an exhaustive inventory of regional and sub-regional transmission planning a little over a year ago, and it is amazing how

short the shelf life of that study was. The conclusion from that is that there's been a lot that's gone on in just the last year, and there will be a lot going on from now on.

I still think we are fairly early in the evolution of where transmission planning is going, and I think this isn't a knock on anybody who is involved in it. I say bravo to them for what they've done, but I think there are some improvements that need to be made.

One of them is not just more stakeholder engagement, but I think more of a multi-disciplinary or an IRP kind of approach to transmission planning that is more robust with respect to alternatives, and it gets really complex because alternatives include energy efficiency and generation and not just other lines. So, it gets hard to do, it is not easy, and that is for sure.

We need some policy and cost allocation. Nobody knows who is going to pay for these things. Is it generators, is it consumers, is it reliability based, is it network based. It is all up in the air. Between FERC and the states, we don't really have very good guidance for potential

developers with respect to who is going to pay.

At the same time, we need better utilization of the current system. It is loaded a small portion of the time, so we need better tariffs which will allow, especially intermittent resources to get on the system, even though they won't necessarily have access on peak, but to have much better access to the system.

Bonneville is pioneering some tariffs in that area, and I think we need to do a lot more so that we can actually get better usage out of the existing system.

Finally, I think we need to avoid the notion that we can achieve perfection in transmission planning. No matter how good a process is and no matter what the outcome is, you are always going to be able to find fault with it because it is such a complex system. So, striving for perfection, I think, is a losing proposition.

My second point is really that California should be even more regional than it is. I don't think any state has done more in terms of analysis and participation at a regional level than California has, so it is not a criticism. It is just a recommendation because

this is a regional system, the grid is regional, the air is regional, the water is regional, and we have no regional government. This is part of the exquisite challenges of the federal system.

We have states and we have the feds and we have a regional market, a regional grid, but no regional government. So, we have to figure it out how to make this thing work on a regional basis, and that means working with the other states. Despite how much the State of California has already done, I would encourage you to do even more, more analytical work, more participation in the various regional entities.

My third point and final point is really about what may be a naked emperor, and that is the role of coal in the West and in transmission development.

You probably can't do major transmission upgrades, especially into the interior West, the Rocky Mountain west without having coal be a major part of that development. Renewables can't pay for it by themselves, and so the question is, should coal or what should be the proper role of coal in the energy future of the West.

What is wrong with coal? Well, coal

causes climate change. Coal causes regulatory risk because of the likelihood of some future restrictions on carbon emissions. There is risk of stranded cost because of these things, so coal has some important things to be wary about.

California should not dictate to other states how they meet their load growth and vice versa. California should dictate how it meets its own load growth, and if part of that load growth is going to be met by coal, then I think California can say here is the kind of coal that we are willing to accept.

Maybe this is better advice for Dan and his Commission with respect to developing a loading order. The action plan's loading order is quite good, but when it gets down to fossil, it is probably not specific enough. Even saying "clean coal" is not good enough.

We are the State of California to say if you get down that loading order as far as coal, then it has got to be the best possible technology that can be built, that means IGCC, a coal gasification process with the prospect at least of future sequestration, even though the technology and economics are not there now for sequestration,

the technology should be put in place so that when that can be done, it can be done, and will be done. In that way, I think California will be responsible for its own consumers and for the welfare of the planet. Thanks.

PRESIDING MEMBER GEESMAN: In the absence of a westwide RTO, where do you see the transmission planning process or the regional efforts at transmission planning evolving?

MR. ANDERSON: Well, that is the $64,000 question. It will evolve I think with the encouragement of regulators. We have some regional activities with SSGWI on the top. I don't think we are going to get any more RTO's than we've got today. I think they've stalled out.

Despite the best attempts of FERC to get them in place, FERC lost on that issue. I think FERC was doing what it did for the right reasons, but for reasons you understand, it didn't work. So, it is going to evolve, and I think regulators need to encourage the processes that are going on from SSGWI down to the sub-regional efforts. New ones are occurring, there is one in Colorado now, and they are all inter-related. I think you just

have to encourage that and see where it goes. I don't see a silver bullet, I don't see a single outcome that I would recommend. I think it is a process kind of a thing that will evolve, and if you apply principles to those processes, I think we will get good results.

PRESIDING MEMBER GEESMAN: Do you see the Devers Palo Verde II project and the cooperation that will require between California and Arizona as really the first test case of the Western Governor's Association protocols of how we are supposed to all get along?

MR. ANDERSON: It is a good test case. I am not an expert on that line per say, but it is going to test the process, and it is going to test the results. Arizona has already sort of fired a shot over the bow by saying, well, maybe we want to take some of that power off at the river, and so, I think there will be some push back in certain ways. So, I think it will be an interesting test case.

PRESIDING MEMBER GEESMAN: Thank you.

MR. SIMONS: I want to follow up on some of the comments --

COMMISSIONER BOYD: Maybe we should

invite Bob back, though, definitely for our coal session later this summer. You made some good points about coal, and Commissioner Geesman and I are going to be here another day to discuss IOGCC coal and its role in our future, so come on back.

PRESIDING MEMBER GEESMAN: Yeah, some time in August. It will be well noticed before we have it, but it will be here some time in August.

MR. SIMONS: I wanted to follow up a little bit on what Bob was talking about also based on some of the comments that we got about better coordination among the different state agencies and jump really to okay, so if we want to have this better coordination between the Energy Commission, the PUC, the CA ISO, and these other out-of-state, interstate organizations, what should be the next steps to do that? Obviously there is some process stuff that really should be happening.

Again, I will just going ahead and maybe --

MR. MUNSON: May I comment on that?

MR. SIMONS: Go ahead.

MR. MUNSON: There is a need for at least one more working group or maybe multiple

working groups to look into the transmission issues associated with north of Lugo, the PDCI north of Cottonwood, and north of Round Mountain and COI. I know our company and other people would like to see a working group formed officially with the agencies and the utilities and the developers and the ISO involved.

We would like to see that happen soon, and we could sit at a table and try to figure this out. Other working groups are making great progress, and Commissioner, you asked me who we thought was the logical party to pay for the upgrades. We think it is the utilities with pass throughs. They have financial health again, and for projects that are going work, the utilities are probably the logical parties to hold those business centers.

The final point from our company would be we certainly support the idea of the renewable loading order, renewable operating loading order is a way of making use of the COI. We think that is a great idea. Thank you.

MR. SIMONS: Jim, PG & E, any response to this?

MR. FILIPPI: Yeah, one thought I have

is that one of the main difficulties with transmission planning and with regional planning efforts that are going on is the perennial question, where are the resources really going to go.

One thing that would really help the development along is some guidance, some policy guidance well thought out comparing all of the alternatives with an assessment of what is the outlook, what are likely to be the preferred resources, amounts and locations. With that, even perhaps some scenarios. With that, the regional planning groups can define better what the transmission alternatives really are, how they are going to work, what they are going to cost, what the impacts might be.

That is just the first step. Then as the process gets farther along and developers get farther along with their work, that should then go into the individual utility and ISO efforts in response to service requests or interconnection studies to actually develop what are the real requirements going to be.

With that information, that is what it is going to take to get the procurement going in a

good fashion where we know then currently what we are going to buy, what we are going to get when we take a contract.

MR. SIMONS: Do you mean that globally from a WECC perspective or starting in California and going up to WECC, I wasn't quite certain if when you are saying you would want --

MR. FILIPPI: Yeah, I am thinking of the sub-regional planning groups like ENTAC for the North, and we were talking about COI issues, those can be discussed at. If you are looking at something like the Southwest Palo Verde-Devers, those can be discussed at STEP. Broader regional issues then could go to SSGWI, they all would roll up to SSGWI. That is a good place where if we have some input on policies about where resources should go could do a better job at identifying what the transmission options are, how effective they are going to be, what the system benefits are going to be.

MR. SIMONS: Okay, great. Dan.

MR. ADLER: Let me just add one thought. You can almost see how it would play out without the competitive bidding element if we have each individual utility's portfolio and their needs

understood overlaying the information that I think we'll get on June 23, which sounds like it will be very useful.

This state level resource assessment with cost and transmission implications inserted bring that to the ISO and saying what do these great interconnections look like from the standpoint of your production costs modeling and from the general categories of benefits to the grid, the economy and reliability, and we are laying on now this sustainability lens if you like.

From a very IOU need specific standpoint, I think that level of connection between the ISO, the analysis you are providing, and the utility procurement plans would be an excellent way to go. Again, how do you turn that into a competitive bidding process at the end is challenging to my mind.

MR. SIMONS: George.

MR. CHACON: I think one of the few things that can be taken or can be looked at is trying to make these projects more realistic. I mean some of the work that we do is on paper, and you know, we try the best we can to do these

conceptual plans and try to identify the conceptual impacts and come up with a conceptual cost, but I think as you look at this morning's presentation, the magnitude of renewables within the state, I look at the ISO and a connection que, and I see very little of that renewable requesting interconnection.

It is quite difficult to come out and give more firm answer, this is what it is going to take and start the permitting process to facilitate the interconnection of the renewables.

The studies themselves would yield better results, would yield a much firmer plan, would be the basis for starting the engineering design of the actual facility, would be the basis for figuring out if special protection schemes can be used to simplify or maximize the existing facilities so that you can better utilize them. Without those studies, it is kind of difficult, we are all guessing. You know, we may be guessing wrong.

I think in the que, as far as Edison is concerned, there is about maybe 1,400 MW of total renewable, and given the magnitude and the amount of renewables in our service territory, I would

have expected to see more, but for some reason, they are not requesting interconnection.

Through those studies, you get the coordination of the other utilities that are non-ISO that are also inter-regional. You get ASRP, APS from Arizona, so I think it is somewhat critical to stress the importance to the developers that interconnection requests are probably the best engine to utilize to move the process along.

The study itself takes about 60 days, then you have the facility study. So, you've already got an inherent time delay that is already there. The sooner you start it, the sooner we finish. If we were to start today, we could probably wrap up the whole process for the one generator in six months. After six months, you are still proceeding down the path of integrating the renewable resource and trying to figure out what the right transmission project would be for interconnecting that particular renewable resource, but it is time well spent because we are going to have to do it anyways.

With that comment, I think the follow up comment is we need to recognize that while the

state has a mandate, you know, we are sort of operating also on with the FERC restrictions as we have to treat all the generators alike, you know, ask for interconnection. At the end of the day, the interconnection study governs what ought to be permitted by the ISO. The ISO reviews those.

I think it is important to keep that in mind and recognize that it is not just economic dispatch. While that is important, you also have to keep in mind the reliability aspects of the facilities and the transmission network.

MR. SIMONS: Jeff.

MR. MILLER: I'd just like to mention a couple of follow on things to these comments. One is there was a lot of focus in the presentations today on COI and on how COI has a serious limit and we've got to build these projects to increase COI capability.

You know, I have studied COI for years, and I know that system is stressed very heavily, and it would be a surprise to me if that wasn't the case, but I will point out that in the last SSGWI study, when they looked at integrating large amounts of renewables, they found out their study could be totally wrong, but their conclusion was

you didn't need to build anything from COI south. That the real problem was getting the power to COI.

You know, unless you look at the interconnection as a whole, you can't really ferret out those issues and make a sound conclusion. So, I think that issue about whether COI needs to be reinforced is still open. The one thing that we haven't talked about is probably the largest impediment that we've been seeing at the ISO anyway to integrating large amounts of particular non-dispatchable renewables like wind has been the operational issues.

If we could find some way of getting to the ideal, which is one large control area for the West, and if you could just do that and free up some of the major transmission limitations, you could integrate a very large amount of wind in the interconnection if you looked at the diversity of wind resources across the interconnection.

Of course, that is an ideal world, but maybe there is some ways even with multiple control areas to try and achieve that same goal. That's it.

PRESIDING MEMBER GEESMAN: We will be

taking up some of those questions tomorrow.

MR. SIMONS: I think we've actually hit -- we've jumped around a lot of the questions, but they have hit most of the questions that were on the list. Does anyone on the panel have any additional comments to make relative to the presentations this afternoon? Jorge.

MR. CHACON: I do have a request. It is not a comment, it is mainly a request. In working with the Tehachapi Collaborative Study Group, we are having a difficult time finding out where within that large block of land hundreds of square miles, the renewable resources would be.

I saw that you had maps up there with wind diversity. I was wondering if you have the information that goes below those maps as to where that potential exactly is that would facilitate the Tehachapi development or at least a conceptual transmission plan a little more.

MR. SIMONS: Yeah, we are happy to provide that.

MR. CHACON: All right, thank you.

MR. SIMONS: Any comments from the audience? Gary. I'm sorry, Gary. One thing that I was asked to comment on is the Northern

California Study Group, and that is something that has been in the works. I don't know what the status of that is. Dave Olsen could have talked about that if he was here today. He isn't, but that is another element that has been discussed somewhat. I just wanted to at least raise that. Go ahead, Gary.

MR. ALLEN: Gary Allen, Southern California Edison. I have been listening intently all day, but there were -- the broad concept that we have been discussing today and especially this afternoon has been importing renewables from out-of-state.

In our recent solicitation, we did have a few out-of-state renewables that were considered bidders. We explored and tried to find a way and we were essentially told by the ISO that we were not able to schedule intermittent renewables over an intertie.

I know they have done some further work on that, they are continuing to consider that, and they may be at a point now where they are more able to deal with that. I think there are some significant issues.

If we aren't able to regionalize how we

schedule intermittent generation, non-block loaded generation over an intertie. Thank you.

PRESIDING MEMBER GEESMAN: I think that's a good point. Jeff, do you have anything to add to it?

MR. MILLER: Yeah. All I can say is because I'm not that close to the issue myself, but the intent of the ISO is to try to facilitate those type of things to the extent that we can handle it operationally. I would point out that even though the ISO is a fairly sizeable entity, when you are talking about interstate transactions, there are other parties out there that have a say in what you do, and there are organizational rules and operational requirements and WECC and so on that we have to follow. So, it may be that some of those are tripping us up. It may be that we are just having trouble getting other parties to go along with it, but it is our intent to try and accommodate those types of transactions.

PRESIDING MEMBER GEESMAN: George, you might flag that as something that we ought to try and track down and learn more about.

MR. SIMONS: Okay.

MR. ROMANOWITZ: Here we are. I think it is on. Thank you, George. I think there were a lot of good points raised here this afternoon and this morning. One point that I would make is I think it is important to integrate the two efforts together.

For example, the Pacific DC intertie passes right through Tehachapi, crosses right over our project property. We don't have to go one mile to get to the Pacific intertie. In the cost numbers that you've got here, it is shown as costing less money per KW by a reasonable margin than the Tehachapi transmission that is in there that runs only 35 miles.

We have obviously some major differences, and really it would be unfairness to try and put a higher cost of transmission on a Tehachapi project which could have this alternative if it works than using these numbers. There is an unfairness in the process that needs to be integrated and tied together, but also a lot of good insight that has come from this process, and I think we hear lots of good things, but there are issues.

Things that were not discussed in the

afternoon session that have been faced on the Tehachapi issue is the n-1 and n-2 limits that CA ISO has of the 1150 and 1400 MW of if you lose the line, you can't lose that. That may have been missed here, that may be why we have some of the numbers that we are seeing, but there ought to be some decent answers that come out of that.

The other thing is that, yes, we do have very good ideas ourselves as to where these projects are going to be. We do have some problems with getting the information, you know, to the utilities and the way they want to see it, but there also is a problem that we have a difficulty or did have and still have a difficulty of moving forward in the que process because we see it as broken.

You can't go through the processes. We see it unless we are missing something, with the process the way it is where you go all the way through the process, and then you sit and wait for a long period of time where you get a power purchase agreement, you have spent your money, and you've lost your position.

So, it is a process that we don't see how it comes together, we are wanting to move

forward to a greater degree and you know, give more information. We do have, for example, the Tehachapi area broken down into 21 separate areas, each area distinctly analyzed as to what density of development it will have. So, we know very well where the development is going. It is all integrated with the military interference and everything. So, there is a lot of work being done.

We would like to move the process along and hope that we can find a way to get this que thing to work so that we can satisfy some of George's questions.

PRESIDING MEMBER GEESMAN: Thank you.

MR. SIMONS: Thanks. I do want to just respond back to you that you are correct, that the work that was done by Ron Davis did take into account the n-1 reliability index and the work by Dennis I don't believe did.

MR. ROMANOWITZ: Okay, it would seem, yeah, in whatever case, it was sort of question because it wasn't clear, but I think that certainly the work they've done gives a lot of good insight that is helpful and it is very helpful to have that information. I'm certainly

supportive of what you have done. I just raise the issues, and there are questions.

There is certainly a discrepancy, however, between the cost this afternoon of using the same line that goes through the same area, and it ought to be easier and cheaper to do it from Tehachapi to Sylmar so we would like to have first dibs on it because we have sort of been discussing these things in the process, you know, for some time, and we can use all 1,500 MW of it.

MR. SIMONS: Okay.

MR. ADLER: Hal, let me ask you a question if I can just so I understand the queuing the problem. There may be something the PUC can at least address (indiscernible).

If you as a developer had say 60 to 90 days notice of when the next RPS RFO was going to come out, and the ISO was staffed appropriately to handled an influx of queuing applications in advance of that (indiscernible), would that be enough notice for you to time your expenditures of money on that study and participate in the RFO?

MR. LAFLASH: Yeah, it probably would, and it may even be that now that we know that the process is going along, we are trying to look at

how we can make this work, and there have just been too many things happening in the last little bit.

I know that Jeff and I have had a discussion at a Tehachapi Study Group meeting not too long ago. They want to try and make it work, and we want to try and help facilitate it. So, we are going to look again on how to make this whole process work. Part of the difficulty is like we have information that we could give available. We were thinking of putting it into the process, but then it is fully public, and there is a lot proprietary information there, so it needs to go in under the confidentiality rules.

This process is sort of difficult to make it come together, but we sure want to make it happen. At least up till now, we have felt, you know, that we couldn't do it. We have turbines that have been sitting there since 1999 not able to get transmission. We have $80,000 in SCE's bank account where we started the process. Essentially, if we went that process, that money would just be gone.

We held it, we didn't move it forward, so it is not a question of putting money into the

process or whatever, we just haven't been able to see a way to get it all the way through. So, what you are suggesting is helpful, and we are trying to move it forward.

MR. SIMONS: Thanks, Hal. Jane.

MS. TURNBULL: Thank you, Jane Turnbull, the League of Women Voters. I just have a question, and that has to do -- I mean there are enormous challenges that have been presented today. I think a lot of good work has been done.

One of the points that seems very evident is the importance of an integrated grid. I guess that one of the points that seems to be implicit in what I am hearing is that the fragmentation of the state grid may be a problem, but that really hasn't been addressed. I think that somewhere along the line, we ought to know whether that is a real problem, and if it is, what the nature of that problem would be.

PRESIDING MEMBER GEESMAN: I think there are a multiplicity of views as to what the likelihood of that changing will be. I know that Commissioner Peevey feels quite strongly that it should change and that we ought to move towards a more unified grid.

Obviously the ISO has felt that way since they started operations in 1998. Our Commission I think traditionally has been a little more respectful of what some would say as balkinzation caused by the Muni's.

We tend to see pluralism as an inevitable feature of a utility system that is partly investor owned and part municipally owned. It unquestionably creates some engineering problems. Steve.

MR. MUNSON: I have to respond our colleagues in the wind industry and ask you please please don't try to grab out PDCI project. We've been working on it for four years, let us have our 500 MW of base load at least. Please guys, you don't need it all.

MR. ROMANOWITZ: Steve, we respect your thing, but we've also been drooling over that line a long time.

MR. SIMONS: Any other comments?

MR. GALLOWAY: Good afternoon, I am John Galloway, and I am with the Union of Concerned Scientists, and I really just wanted to be another voice in the choir and sing the line that some other folks here today brought up with regards to

coal from the intermountain west.

With a few exceptions such as wind and hydro shaped type products, it would seem that a lot of discussion that we had this afternoon around transmission and transmission capacity could really apply to any resource, not just renewables, but could also apply to coal and gas resources throughout the region.

I guess my chief concern there would be keeping in mind as we go forward is to look at coal from the intermountain west, and it would really be interesting to overlay the coal potential and where coal plants are being proposed.

I don't know if you looked some projections from the Department of Energy of where coal is being proposed in the West, how that overlays with renewable energy potential, so as we are talking about building these lines, I think, Mr. Wellinghoff earlier this afternoon said fairly well we should really be asking questions and be concerned about what is competing for the lines we are talking about. I would be very concerned if we are looking at all of this transmission that is being built to get renewables, but really in truth

what we are going to be doing is pulling coal down those lines, particularly if we are not talking about the loading orders I believe.

Mr. Anderson pointed out about the definition or how we are contextualizing fossil resources in the loading order, we haven't really articulated a policy for what can go on those lines and what kind of fossil we are going to be accessing in the coming years, particularly in the long term resource plans of the utilities. That is not very well spelled out.

I would just again encourage the integration of all of our transmission -- as you do the integration of transmission capacity into the IEPR, that you also overlay that with the resource plans of the utilities and consider the full spectrum of resources and those lines aren't necessarily just going to be used for renewables. Thank you for holding this workshop today.

PRESIDING MEMBER GEESMAN: John, how do you respond to what Bob Anderson suggested that the lines are unlikely to be financeable solely with the renewables as a likely generation source?

MR. GALLOWAY: That is going to be an interesting challenge in the utility resource

plans, particularly as the CEC goes through its analysis of the needs assessment for the utilities. I guess I don't have a clear response just off the cuff on how we are going to address that, but I think looking at the in-state resource potential first before we talk about pulling in wind from Wyoming or Southern Montana, I think it would be key in these discussions and some of the immediate and surrounding areas that can access existing transmission capacity.

I would be very concerned that if we are going to -- if conventional resources are going to finance those lines, it needs to be for coal for example, we have to be talking about integrated combined gasification and sequestration. We just can't be talking about coal as a generic resource.

PRESIDING MEMBER GEESMAN: Thank you.

MR. MUNSON: Commissioner.

PRESIDING MEMBER GEESMAN: Yes.

MR. MUNSON: I think one thing that is clear though, our company and our consultants at Beck have run a lot of numbers on transmission lines. The base load renewables will be in the same position as fossil. In fact, somewhat better, we are getting 95 to 98 percent capacity

factor. The problem that will be probably financing intermittence because of the low line use.

PRESIDING MEMBER GEESMAN: I still don't see any of the base load renewables looking to step up and finance transmission projects. Your industry seems to have its hands full trying to finance generation.

MR. MUNSON: It is our understanding, sir, that there is a transmission planning process under way that is going to determine who is going to pay.

PRESIDING MEMBER GEESMAN: Dan.

MR. ADLER: Let me just add and kind of echo I think the point that you raised earlier, Commissioner, that the trunk line proposal is more than just Tehachapi. It could become the vehicle not just for California, but for the United States as far its renewable transmission planning. That is point number one.

Slightly unrelated, is in the loading order of fossil resources, we do have the carbon risk adder now that at least as an analytic mechanism will differentiate inside the fossil fuel portfolio when the utility is doing its

planning.

PRESIDING MEMBER GEESMAN: What is the dollar value you have associated with that?

MR. ADLER: Initially it is $8.00 a ton CO2 equivalent, it escalates modestly over time, but to a lot of people, that's too little. I think we may find that it is too little, but it turns into $3 to $10 a MW hour on an analytic basis depending on the resource.

MR. MUNSON: Commissioner, I didn't come off well on that last comment. The customer pays for the transmission no matter whether the developer is billing the grid and charging the utility. We all know that, and ultimately that is where the payment comes from. The grid needs fixed, and we won't meet this RPS if some of these things aren't fixed.

PRESIDING MEMBER GEESMAN: Grace.

MS. ANDERSON: Grace Anderson with the California Energy Commission staff. I can't let this go by without introducing another acronym that starts with "W". You asked where is this regional transmission planning going to evolve, and the answer is we really don't know, but there is an industry based group of people that go under

the acronym of Western Assessment Group, the WAG. They are having their first meeting on the 23rd of May where they are having a stakeholder commenting session a paper they have written that tries to identify different options for some kind of an institution in the west that would look at five specific commercial issues and resource adequacy is one of those, but also transmission planning.

Certainly the WECC taking on a larger role in this area is one of the really important possibilities and it may or may not occur. It is going to take more resources, though, before whomever is going to do it in the future, so the Energy Commission or the State of California certainly can be an advocate of this function being more robust and the resources coming from somewhere in the West.

Jeff and I were in a meeting last week where DOE sent a representative to the SSGWI planning work group, and it is really unusual for DOE to appear at something like that. In fact, they never have before. So, we were kind of wondering what this person was doing in the room, and he is actually one of our strongest fans.

Larry Mansueti, his basic message that

the feds are going to move ahead, and they are going to do that without the federal energy legislation. He gave us several specific paths that they are going to move forward on, but two of those are that DOE independent of any legislation is going to complete a process for designation of national interest transmission constraints. That is a new word they are using. That would allow any party to come forward and propose such a designation. That could be a developer, it could be a state, it could be a sub-regional group.

Those proposers would have different hurdles that they would need to cross over to have the designation granted, but once it is granted, that immediately puts it on the list for FERC to have the backstop siding authority if the legislation passes. So, that is a piece of the puzzle that isn't automatic.

The more we work in the West and on our own issues that we've heard today, the more we will be positioned to either support or to have a role in deciding what constraints are designated because it could easily play out in the future if FERC will get that backstop authority.

The other --

PRESIDING MEMBER GEESMAN: The last time they did that, though, the only line of national significance in the western states was the Path 15 upgrade. That is primarily a red state/blue state drill that may not have much applicability in the West.

MS. ANDERSON: When they move to the word "constraint" though, that may give them a lot more latitude, and when they open the door to anyone being able to put forward a request for a designation, all the subregional studies, you can point to any of them, and there would be any number of constraints, constrained paths, so just something we want to be watchful of, and they more we are organized, the more we can make a compelling case that the West can act on its own and doesn't really need DOE to be doing this for us.

His other point that they are moving forward with is the CEQ is taking the next steps of putting out the money and gathering the data through Argon for the environmental work on the corridors across federal lands. Jeff, speak up, you are in room too, but that is that next step forward to someone else deciding where these lines

may be coming from and what scarce resources they are going to be stepping on along the way.

You know, as Jim has said very eloquently, it is where the resources are in the West in the future that is going to drive which corridors are the ones that get focused on.

I'll just end by saying that this whole question of the generation future is one that we really need to if we can as a Commission step forward on and in fact, what we think could occur over the next month or so is that the Energy Commission's staff 2015 resource case, which was developed for the Western Gas Study, could become the reference case for the 2005 SSGWI interconnection wide expansion planning.

From there, someone, the powers that be, a few of us who care enough to go to Portland every couple of weeks will say, okay, we are going to test this transmission scenario against that reference case, this generation future against that reference case. The more that the Commission can daylight its own work as that moves out into the West, then the more you will be able to feel that we've got a robust position to put forward out there.

As it is, we are very fortunate that we are the analytic might of the states in the West in many respects. That contribution is really invaluable, and I am an advocate of continuing it. Thank you for that support, I know you guys provide it.

PRESIDING MEMBER GEESMAN: Thank you, Grace. Other comments from the audience.

MR. WEINBERG: I'm Carl Weinberg, and I don't represent anybody, but myself in these comments. I do have a little background on utility operations and energy research and development.

I was listening all day today, and I listened to the discussions about the procurement process, and I listed to this afternoon to the studies. I think you are rapidly moving to paralysis by analysis.

PRESIDING MEMBER GEESMAN: I agree.

MR. WEINBERG: I don't know exactly what the Commission is going to do about that or whether it is your job to do anything about it, but --

PRESIDING MEMBER GEESMAN: It is our job. I don't think we will make anybody happy.

MR. WEINBERG: Yeah, well I think somewhere you need to get off with some people who will sink through and say what can we do because I see no way if any of the discussions that were on today that you are going to meet your goal in 2010 unless there is some intervention in the process because I think you are already in paralysis by analysis.

PRESIDING MEMBER GEESMAN: I completely agree. Did you live through the BRPU process before?

MR. WEINBERG: I am still here and barely.

PRESIDING MEMBER GEESMAN: Other comments from the audience. Okay, it has been a long but fruitful day. I want to thank everybody for your participation and look forward to seeing you again.

(Whereupon, at 4:10 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 19th day of May, 2005.

Peter Petty